ENERGY
MANAGEMENT
SERIES

5

FOR INDUSTRY
COMMERCE
AND INSTITUTIONS

Combustion

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada
Canada

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PREFACE

Much has been learned about the art and science of managing energy during the past decade. Today, energy management is a seriously applied discipline within the management process of most successful companies.

Initially, in the early 1970's, energy conservation programs were established to alleviate threatened shortages and Canada's dependency on off-shore oil supplies. However, dramatic price increases quickly added a new meaning to the term "energy conservation" — reduce energy costs!

Many industrial, commercial and institutional organizations met the challenge and reduced energy costs by up to 50%. Improved energy use efficiency was achieved by such steps as employee awareness programs, improved maintenance procedures, by simply eliminating waste, as well as by undertaking projects to upgrade or improve facilities and equipment.

In order to obtain additional energy savings at this juncture, a greater knowledge and understanding of technical theory and its application is required in addition to energy efficiency equipment itself.

At the request of the Canadian Industry Program for Energy Conservation, the Commercial and Institutional Task Force Program and related trade associations, the Industrial Energy Division of the Department of Energy, Mines and Resources Canada has prepared a series of energy management and technical manuals.

The purpose of these manuals is to help managers and operating personnel recognize energy management opportunities within their organizations. They provide the practitioner with mathematical equations, general information on proven techniques and technology, together with examples of how to save energy.

For further information concerning the manuals listed below or material used at seminars/workshops including actual case studies, please write to:

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Energy Conservation Branch
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INTRODUCTION

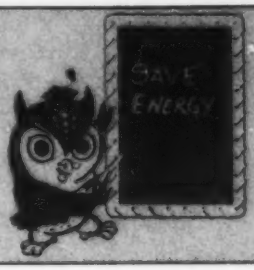
Combustion occurs in many forms daily in modern society. Combustion processes include the burning of natural gas or oil in a home furnace, the combustion of gasoline in an automobile engine, the burning of natural gas, oil, coal or wood in a boiler that produces steam or hot water and many highly sophisticated production operations which utilize combustion to produce heat and special reducing atmospheres. The objective of this module is to describe the basic principles of combustion and the supporting calculations which would help to identify Energy Management Opportunities for boilers, industrial furnaces and kilns and varied processes.

Combustion is a complex subject and substantive changes to the process should only be contemplated after consultation with the regulating bodies having jurisdiction, the manufacturer of the fuel burning equipment, the control system supplier and other trained specialists.

This module describes combustion principles, equipment and energy saving opportunities. A brief summary of the module sections follows:

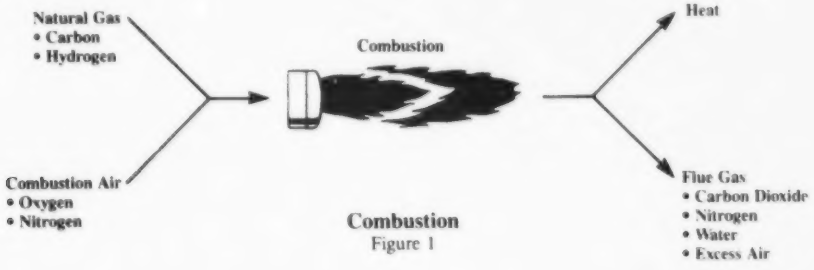
- *Fundamentals* of combustion describes the chemistry, the factors which affect combustion efficiency, the measurements used to determine operating efficiency and the calculation of energy losses.
- *Equipment/Systems* describes the types of combustion equipment, related metering and control systems, and heat recovery equipment.
- *Energy Management Opportunities* provides examples of how the combustion process can be improved to save energy.
- *Appendices* contain a glossary, tables, curves, common conversions and worksheets to assist in calculating combustion efficiency.

FUNDAMENTALS



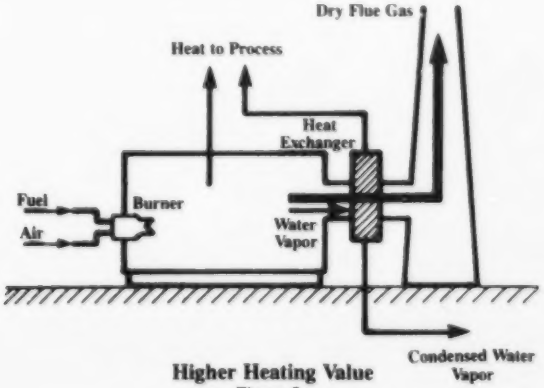
Combustion may be defined as a rapid chemical reaction in which oxygen combines with the combustible elements of a fuel releasing large amounts of energy and forming new chemical compounds. The combustion process for natural gas is shown in Figure 1.

All chemical reactions can be characterized as being either endothermic or exothermic. Endothermic reactions require that heat be added to the reactants for the reaction to take place, whereas exothermic reactions release heat. Combustion reactions are a combination of these two types because heat must be added to start the reaction but once started, large amounts of heat are released. The combustion of fuels is used as a source of light, heat, and to create a reducing atmosphere for other chemical processes.

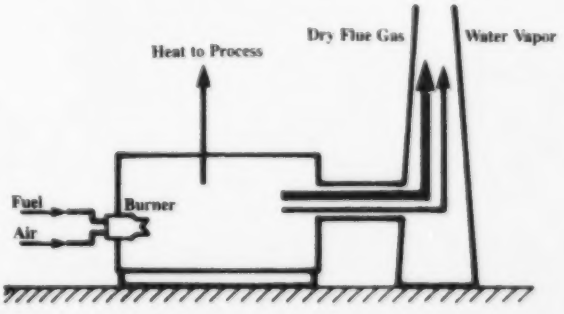


Combustion
Figure 1

Energy is released during combustion in the form of heat and light, with heat normally being the required energy form. Fuels can be characterized by the amount of heat released from the burning of a unit amount. The *Higher Heating Value* (HHV) is defined as the heat which would be released by completely burning the fuel to carbon dioxide and water, and condensing all the water to its liquid state at 25°C (Figure 2a). The *Lower Heating Value* (LHV) assumes the water vapor formed is lost up the stack. The heat of vaporization of the water formed is subtracted from the total heat, resulting in the lower heating value of the fuel (Figure 2b). Higher Heating Values will be quoted throughout the module.



Higher Heating Value
Figure 2a



Lower Heating Value
Figure 2b

Combustion

Today natural gas, various grades of fuel oils, wood and coal are the most commonly used fuels. Natural gas predominates where there are pipelines because it is easy to use, burns cleanly and is relatively inexpensive. Examples used in this section will deal with natural gas, but characteristics of fuel oils, coal, and wood are described in Tables 5, 6, and 7.

Natural gas is made up of several compounds, chiefly methane and ethane (CH_4 and C_2H_6 respectively) which are in turn composed of the elements carbon and hydrogen. There are other constituents in natural gas but they make up a small fraction of the total, and do not contribute significantly to the energy released during combustion.

When natural gas burns, carbon atoms combine with oxygen atoms in the air to form carbon dioxide (CO_2). Hydrogen atoms combine with oxygen, forming water (H_2O). The nitrogen from the air, and non-combustible compounds in the fuel pass through the processes essentially unchanged.

If the combustion process is complete the gases leaving the combustion chamber are mainly CO_2, H_2O (water vapor), nitrogen and trace amounts of the oxides of nitrogen and sulphur.

Relationship of Time, Temperature and Turbulence

The objective of combustion is to release all of the available heat while minimizing losses from combustion imperfections. The combining of the combustible elements of a fuel with oxygen requires turbulence to mix the fuel and air, a temperature high enough to ignite the mixture, and sufficient time for complete combustion. These factors are often referred to as the three T's of combustion.

A short burning time, high temperature and a very turbulent flame are the result of good combustion. Turbulence is the key because the fuel and air must be mixed thoroughly if the fuel is to be completely burned. If they are not well mixed complete combustion may not occur, the flame temperature is lower, and the fuel will take longer to burn.

Fuels Overview

Natural gas, oil, coal and wood are the most commonly used fuels. Other fuels are used to a lesser extent in Canada. Many of these are by-products of other industrial processes and their use represents an excellent opportunity to displace the use of nonrenewable fuels such as coal and petroleum based fuels. Table 1 lists the more common fuels, the main constituents, higher heating values, and the combustion reactions that they undergo.

Natural Gas

Natural gas is a very popular fuel with several advantages over other fuels:

- On-site storage is not required
- Mixes readily with air, without specialized atomizing apparatus
- Clean burning
- High heating value (37.2 MJ/m^3)
- Low sulphur content for less pollution
- Relatively inexpensive

Fuel Oils

Fuel oil is more difficult to handle and burn than gas. Oil must be stored on-site in tanks, pumped to the point of use and is often heated to flow properly. It must also be atomized at the burner to achieve good combustion. With the preponderance of conversions to natural gas, fuel oil is slowly being relegated to use as a back-up fuel.

There are several grades of fuel oils that vary with the amount of refining from the crude state. No. 2 light oil, and No. 6 heavy oil (Bunker C) are typically used. The lighter No. 2 oil flows easily and can be atomized without heating. No. 6 oil is heavier, more viscous, and requires heating to the range of 80 to 105°C for good atomization. Typical Higher Heating Values for No. 2 and No. 6 oils are 38.68 MJ/litre and 41 MJ/litre respectively. The heating value of No. 6 oil also varies with the composition. The table of heating values on page C-5 shows that the higher heating value of No. 6 oil varies from 40.2 to 42.3 MJ/litre as the sulphur content increases from 0.5 to 2.5 percent.

Fuel oils contain varying amounts of ash, which are substances that generally do not burn, but deposit on heat transfer surfaces as well as leave the furnace in the form of soot. Ash carries away some of the heat released during combustion but the effect is not great.

Coal

Coal, the most popular solid fuel, is difficult to use primarily because of the handling equipment required for the coal and ash. The capital expense is also considerably greater for the larger, more complex furnaces, pulverizers, burners or stokers, coal bunkers and coal and ash handling equipment. For suspension firing, pulverizing ensures the intimate contact with heat that is necessary to gasify the combustible elements. The gasification process is necessary because the combustibles burn as a gas, but will not burn while in a solid state. Grate fired coal is burned in lump form but requires a longer period to drive off the combustible gases which then burn.

Coal contains more ash than oil, and varying amounts of sulphur and moisture. Coal is mostly comprised of carbon with very little hydrogen. The exact composition and heating value of coal varies with the particular coal deposit. Harder, higher-grade coals such as anthracite have heating values of approximately 30 000 MJ/tonne whereas low grade sub-bituminous and lignite coals have heating values of 16 000 to 22 000 MJ/tonne.

Wood

Wood, wood chips, and wastes from sawmills and forests are complex vegetable tissues composed principally of cellulose, an organic compound whose main constituent is carbon. Freshly cut wood has a moisture content that varies from 30 to 50 per cent. Wood should be stored where it will not be exposed to rain and absorb water.

The heating value of wood varies widely with the species of tree owing to the presence of resins, gums and other substances. Typically, heating values average 18 000 to 20 000 MJ/tonne.

Combustion Chemistry

Combustion is a chemical process in which the hydrogen and carbon in a fuel are rapidly oxidized by oxygen in the air. Combustion reactions may be represented as a series of chemical equations which show the number of atoms of oxygen that combine with one or more atoms of each combustible element present.

The amounts of carbon (C) and oxygen (O_2) required for the complete combustion of carbon are represented by the following equation.

Carbon + Oxygen = Carbon Dioxide + heat (Table 1)
C + O_2 = CO_2 + 32.79 MJ/kg

The equation for the combustion of hydrogen can similarly be shown.

Hydrogen + Oxygen = Water + heat (Table 1)
$2H_2$ + O_2 = $2H_2O$ + 142.07 MJ/kg

Some fuels contain a small amount of sulphur which when burned produces sulphur oxides that pollute the air and may corrode equipment, breeching and stack if allowed to cool below the dewpoint of the flue gases. The equation for the combustion of sulphur is shown below.

Sulphur + Oxygen = Sulphur Dioxide + heat (Table 1)
S + O_2 = SO_2 + 29.6 MJ/kg

In all of these reactions, weights equivalent to an element's molecular weight in kilograms combine. These weight equivalents are known as *moles*. It has been established through experiments that equal volumes of gases at any given pressure and temperature contain the same number of molecules. However, since the molecular weights of all elements are different, the weight of equal volumes of gases are proportional to the respecive molecular weights. For example, the mass of one mole of carbon is 12.011 kg and the mass of one mole of oxygen is 32 kg. The combustion equation accounting for molar quantities is shown below.

(1 mole) C + (1 mole) O_2 = (1 mole) CO_2
12.011 kg + 32 kg = 44.011 kg

The following example illustrates the use of the mole concept in calculating the amount of energy released during the combustion of natural gas. Assume one mole of natural gas containing 85% methane and 15% ethane is burned completely. Since natural gas is a mixture of carbon and hydrogen it is necessary to first calculate the total mass of each element in the gas sample. The mass of one mole of hydrogen is 1.003 kg.

Fuel	Carbon Content # Moles	Mass	Hydrogen Content # Moles	Mass	
Methane (CH_4)	= 1 x	12.011	+ 4 x	1.008	= 16.043 kg/mol
Ethane (C_2H_6)	= 2 x	12.011	+ 6 x	1.008	= 30.07 kg/mol
			Total Mass (natural gas)		= 46.113 kg/mol

% Carbon in Natural Gas

CH_4 (85%): $\frac{12.011}{16.043}$ x 0.85 x 46.113 = 29.35 kg

C_2H_6(15%): $\frac{24.022}{30.07}$ x 0.15 x 46.113 = 5.53 kg

Total Mass of Carbon in Natural Gas = 34.87 kg

% Hydrogen in Natural Gas

CH_4 (85%): $\frac{4 \times 1.008}{16.043}$ x 0.85 x 46.113 = 9.85 kg

C_2H_6(15%): $\frac{6 \times 1.008}{30.07}$ x 0.15 x 46.113 = 1.39 kg

Total Mass of Hydrogen in Natural Gas = 11.24 kg

Total Mass of Natural Gas = 34.87 + 11.24 = 46.113 kg

Heat Released in Combustion Reaction

Carbon:

34.87 x 32.79 $\frac{MJ}{kg}$ (Table 1) = 1143.39 MJ

Hydrogen:

11.24 x 142.07 $\frac{MJ}{kg}$ (Table 1) = 1596.98 MJ

Total 2740.37 MJ/mole natural gas

Temperature Considerations

Heat energy must be added to a mixture of fuel and air in order for a combustion reaction to begin. Heat must also be constantly added to sustain combustion. After the reaction begins, the temperature in the combustor will increase until more heat is released than is required to sustain the reaction. The *ignition temperature* is the lowest temperature at which combustion can be sustained by the heat generated in the burning of the fuel-air mixture. The ignition temperature may be lowered by increasing the pressure on the fuel/air mixture delivered to the burner.

When a fuel burns, some of the heat released is lost through several mechanisms. If the system could operate with no heat loss then the maximum or *adiabatic flame temperature* would be reached. Adiabatic conditions are ideal conditions in which no heat transfer occurs. Adiabatic flame temperature is the theoretical maximum temperature that is possible in a combustion reaction. It is a useful concept because it helps establish thermodynamic limits and aids in the selection of materials that must be specified for use within the combustion zone.

Combustion Air

The basis of all combustion reactions is the rapid oxidation of a fuel in a strongly exothermic chemical reaction. In all cases, molecules of the fuel elements, carbon, hydrogen and sulphur combine with oxygen from the air to produce CO_2, H_2O and SO_2.

The reaction equations show that definite quantities of fuel and air (oxygen) are required for the reaction to be completed. For example, in the oxidation reaction of carbon ($C + O_2 = CO_2$) one mole of carbon (12.011 kg) reacts with one mole of oxygen (32 kg) to produce one mole of carbon dioxide (44.011 kg) and 393.8 MJ of energy. If only 0.8 moles of carbon are available, then 0.8 moles of oxygen are required for combustion and 0.8 moles of CO_2 and 0.8 x 393.8 = 315 MJ of energy will be released.

Combustion reactions will consume all the fuel supplied according to the theoretical air-to-fuel ratio known as the *stoichiometric ratio.* Stoichiometric ratios may be expressed in terms of the mass of oxygen per mass of fuel, moles of oxygen per mole of fuel or volume of oxygen per volume of fuel.

The following example illustrates a method for calculating the stoichiometric ratio for a sample of natural gas. Assume a natural gas sample with the analysis of 85% methane and 15% ethane. The amount of oxygen required to completely convert the fuel components to CO_2 and H_2O may be calculated on the basis of one mole of fuel.

From the reaction equation $2C_2H_6 + 7O_2 = 4CO_2 + 6H_2O$ it can be seen that 7 moles of oxygen are required for every two moles of ethane in the fuel. Therefore, to burn all of the ethane in the sample, 7 x 0.15 = 1.05 moles of oxygen are required.

From the reaction equation $CH_4 + 2O_2 = CO_2 + 2H_2O$ it can be seen that two moles of oxygen are required for every mole of methane. Therefore 2 x 0.85 = 1.7 moles of oxygen are required for the complete combustion of methane in the sample.

Almost all combustion processes rely on air as the source of oxygen. Air is a mixture of many different gases and contains only 21% oxygen with nitrogen making up most of the remainder. For calculating combustion air requirements it can be assumed that air is comprised of 21% oxygen and 79% nitrogen. Thus, if one mole of oxygen is required for the combustion of one mole of carbon, 1/0.21 or 4.76 moles of air are required to supply the necessary oxygen.

The stoichiometric oxygen required for complete combustion of the natural gas sample is 1.05 + 1.7 = 2.75 moles, and the stoichiometric air is 2.75 / 0.21 = 13.1 moles of air per mole of fuel. This ratio may also be expressed according to the volume of air and fuel so that 13.1 m^3 of combustion air are required for every cubic meter of natural gas burned.

In actual applications it is impossible to achieve perfect mixing of the fuel and air so more combustion air must be used than the stoichiometric amount. This is termed *excess air,* the amount of which varies with the fuel, type of firing equipment, and the firing rate relative to the system design. Typical excess air quantities required for the proper combustion of most fuels are given in Table 2.

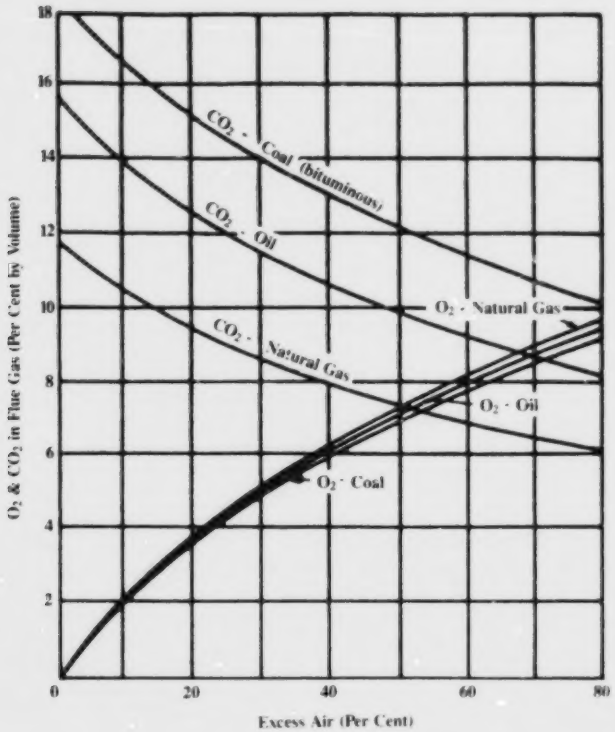
Excess air, that is not used for burning, is heated in the combustion chamber and exits from the system carrying with it valuable energy. The amount of excess air must therefore be kept to a minimum to minimize the loss of heat up the stack. Excess air causes more fuel to be burned to perform a task because more of the available heat is being lost in the flue gas. Adherence to the time, temperature and turbulence concepts will help to minimize excess air in a combustion system.

By measuring the per cent oxygen or carbon dioxide in the flue gas the percentage excess air for oil, natural gas, and coal can be obtained from Figure 3, provided that CO is not present. For other fuels, or when there is CO in the flue gas, the following equation can be used.

$$\% \text{ Excess air} = \frac{O - 0.5CO}{0.2682N_2 - (O_2 - 0.5CO)} \times 100$$

Where O_2 = per cent oxygen by volume
CO = per cent carbon monoxide by volume
N_2 = per cent nitrogen by volume.

In most industrial sized combustion systems air is fed to the combustor with a forced draft blower that supplies the required quantity of air at a pressure that assists in creating a turbulent environment for combustion. In smaller systems, the natural draft created by hot gases rising in the stack can be enough to draw in combustion air through the combustor. However, the distribution and control of combustion air and the subsequent mixing with fuel is not as good as with a pressurized forced draft system.



Per Cent O_2 and CO_2 Versus Excess Air For Various Fuels
Figure 3

Heat Transfer

Energy released in a combustion reaction must be transferred to a product or process. The heat transfer takes place through three mechanisms, conduction, convection and radiation (Figure 4).

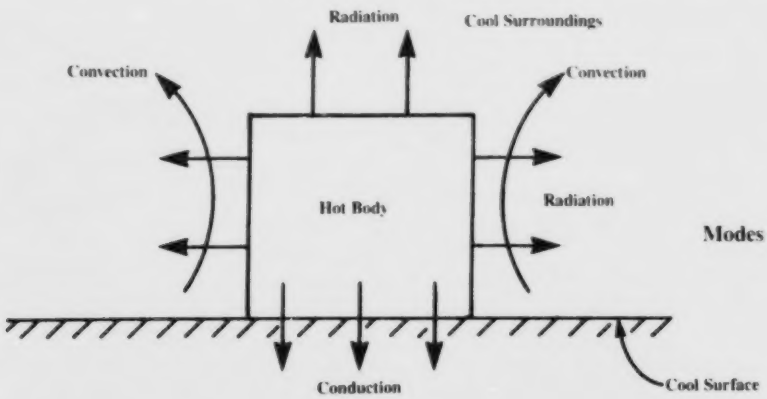
Conduction

Conduction heat transfer occurs when heat travels through an object. For example, if one end of a metal rod is placed in a fire the other end will become hot due to the conduction of heat through the rod. The rate of heat transfer is proportional to the thermal conductivity of the material and inversely proportional to the material thickness.

In combustion systems, heat losses must be minimized. This means reducing the amount of heat conducted through the combustion chamber walls to the outside. As the preceding paragraph indicates, the best way to do this is to increase the insulation thickness or use insulation with a lower thermal conductivity.

Convection

The transfer of heat that occurs between the hot gases in a furnace, and a product that is being heated, is by movement of the gas. If the movement is caused by temperature differences within the gas, the process is called



Modes of Heat Transfer
Figure 4

convection. Tests on the rate of heat transfer by convection show that it is proportional to surface area and temperature difference between the solid and the gas. It also increases as the velocity of the gas over the surface increases.

Radiation

Radiation heat transfer is a process by which heat flows from a higher temperature body to a lower temperature body when the two bodies are not in contact. For example, a person can feel the heat radiating from a fire without getting close to it. Heat transferred by radiation from a body is proportional to the fourth power of the body's temperature.

Energy Losses

Energy losses from the combustion process reduce the amount of heat that is available for use. As a result proportionately more fuel must be used to produce a given amount of usable energy. Most energy is lost up the stack either from the incomplete burning of a fuel or from temperature related losses in the flue gases.

A very efficient combustion/heating system has a relatively low flue gas temperature, because most of the heat generated is transferred to the product. Conversely, higher flue gas temperatures represent greater losses. Losses due to radiation from the combustion chamber, and smaller unmeasurable losses generally account for approximately 5 per cent or less of total losses.

Incomplete Combustion

Incomplete combustion will occur when any of the combustible elements in the fuel are not completely oxidized. It represents a loss of efficiency because a portion of the heating value of the fuel goes unused. The loss is in proportion to the amount of fuel that is not oxidized. Lack of excess air or insufficient mixing are the two major causes of incomplete combustion. Some of the other causes are described below.

- Insufficient residence time of combustibles in the combustion chamber.
- Quenching of the combustion reaction as a result of contact with a cold surface.
- Reduction in the reaction rate as a result of heat losses from the reaction zone.

The products of incomplete combustion are fuel fragments that have not had the opportunity to fully react. If combustion is incomplete, an analysis of the flue gases will reveal the presence of carbon monoxide (CO), indicating that carbon has been only partially oxidized. The following equation demonstrates this effect.

$$2C + O_2 = 2CO + 9.21 \text{ MJ/kg}$$

Notice that some heat is given off by this partial reaction. Carbon monoxide is a combustible gas and if it could be burned to form carbon dioxide more heat would be released. The sum of the heat released in this two stage combustion process is equal to the heat released when carbon is oxidized directly to CO_2.

Carbon monoxide emissions can be controlled by taking certain precautions.

- Provide sufficient excess air.
- Provide good mixing of fuel and air (turbulence).
- Decreasing the firing rate (longer residence time).
- Maintaining high temperatures in the combustion chamber by reducing excessive radiation heat loss with insulation (temperature).

Flue Gas Losses

By far the greatest heat loss is up the stack, with higher flue gas temperatures representing higher losses. Stack losses are the sum of five components: (1) the *sensible heat* in the dry flue gas, (2) water formation from the combustion of hydrogen (3) the sensible heat in the vapor from water in the fuel, (4) the *latent heat* of the vapor from moisture in the fuel, and (5) the sensible heat in the vapor from moisture in the air.

The dry flue gas sensible heat loss is equal to the amount of heat in the dry flue gas compared to the heat in the flue gas at ambient temperature. Graphs of all significant sources of heat loss for most common fuels are included in Appendix D and can be used to calculate system losses. The dry flue gas loss curves (Appendix D, Fig. 4) for natural gas show that losses are directly proportional to the excess air per cent. The excess air that is not used in the combustion of the fuel also leaves at an elevated temperature. The energy required to heat this

air from ambient temperature to the temperature of the gas leaving the stack serves no purpose and is lost heat.

The combustion reactions show that water is formed as a result of the combustion of hydrogen. This water vapor contains latent heat of vaporization and superheat in an amount proportional to the temperature difference between 100°C and the flue gas temperature. Little can be done in the combustor to overcome this since it is a function of the chemical composition of the fuel being burned. Recovering as much of this heat as possible from the flue gas minimizes the loss from this and other effects.

Moisture in the fuel can represent a more significant loss for fuels like coal or wood. Moisture in fuel absorbs energy as sensible heat until 100°C, energy as latent heat until converted to vapor and again as sensible heat as it is superheated beyond saturation temperature. Unless some form of heat recovery is utilized in the flue gas stream all of the sensible and latent heat is lost. Wood and wood wastes can have high moisture levels due to the natural moisture in freshly cut timber and from exposure to water while transporting, storing, and from debarking operations. Moisture levels in coals are considerably lower but still contribute to combustion heat loss.

Moisture in the combustion air enters the combustor as a vapor but is heated to the flue gas temperature by the combustion reaction. The energy used to raise the vapor temperature is lost from the system, however this loss is largely uncontrollable and represents a small fraction of the total losses.

Radiation and Convection Heat Losses

Heat losses from the combustion chamber occur as a result of radiation and convection. Both effects are proportional to the surface temperature of the combustor walls. Radiation and convection heat losses in furnaces, ovens, and kilns can be determined from Table 3. Radiation losses from boilers can be determined from Table 4.

Combustion Efficiency

Efficiency is a measure of how much useful energy is obtained from a system relative to the amount of energy supplied to the system. The term *combustion system efficiency* can be used to represent the efficiency of a boiler, furnace, kiln or other combustion devices. For a system with a useful heat output such as a steam or hot water boiler the *Direct* and *Indirect* Methods can be used. The Direct Method is explained first.

$$\text{Efficiency} = \frac{\text{Heat output}}{\text{Heat input}} \times 100$$

For a steam boiler this calculation requires measurement of both the heat input (fuel flow and feedwater temperature) and the useful heat output (steam flow, pressure, and temperature). Significant errors can result because of inaccurate measurements, particularly at the lower flowrates.

Worksheet 5-1 has been developed to simplify efficiency calculations using the direct method. The following example illustrates the use of the worksheet.

A boiler generates 42 500 kilograms of steam per hour at a pressure of 1500 kPa (abs). Natural gas with a higher heating value of 37.52 MJ/m^3 is burned at the rate 3294 m^3/h. The boiler is continuously blown down at a rate of 4% of the steam produced.

Steam tables are required to calculate enthalpies from steam pressures and water temperatures. Using Worksheet 5-1, the direct efficiency is calculated to be 81.8%.

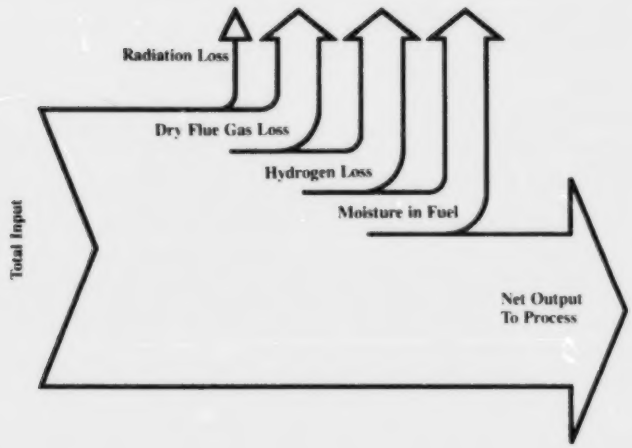
The direct method can be applied to furnaces or kilns as well as boilers. In such cases however, measurement of heat transferred to the product, to waste dust particles, and in the case of cement to the heat of formation of the product is required.

For any furnace, oven, kiln, or boiler, the overall combustion efficiency is 100 per cent minus the summation of all losses. This principle is illustrated in Figure 5. The combustion system efficiency using the indirect method can be expressed in equation form.

$$\text{Efficiency} = \left[1 - \left(\frac{\text{Total Losses}}{\text{Total Inputs}}\right)\right] \times 100$$

The input, output, and the losses are all measured in consistent units such as Joules/kg fuel.

The indirect method is normally recommended for the determination of efficiency. It has the additional benefit of allowing easier identification of areas where efficiency can be improved.



Heat Losses From The Combustion Process
Figure 5

In this module total losses will be the sum of losses due to the following:

- Dry flue gas losses.
- Water formation from the combustion of hydrogen (hydrogen losses).
- Radiation.
- Moisture in fuel.
- Carbon monoxide in the flue gas.
- Combustibles in refuse.
- Unaccounted for losses.

Several operating parameters of the combustion system must be measured in order to calculate these losses. An analysis of the flue gas is helpful to determine excess air, which together with flue gas temperature and combustion air inlet temperature is usually sufficient to allow an accurate evaluation of the losses. Where combustion is incomplete, carbon monoxide (or carbon particulates in solid fuel systems) must be measured to determine the energy loss due to incomplete combustion.

All measurements should be made as close to the combustion chamber as practical. The flue gas analysis can be distorted by air leaks in the breeching, resulting in higher measured excess air readings than actually exist. This could lead the technician to adjust the burner for lower excess air resulting in the loss of combustibles in flue gas.

Measurements should be made at several different firing rates over the burner turndown ratio. Burner settings and controls normally require increased excess air as the burner is turned down with the amount a function of the burner design and set-up. Tests made only at the high firing rate will not indicate this condition. Several measurements made over a period of time will also reduce the chance of a short term deviation being measured and mistaken for normal operation.

Observation of the flame can be useful to determine if the degree of turbulence seems adequate and if there is impingement of the flame on heat exchange surfaces which could lead to degradation of the material. The color of the flame is an indicator of excess air conditions; when burning natural gas, a clear blue flame indicates good mixing and adequate air supply, whereas a yellow flame indicates insufficient combustion air and/or poor mixing. It should be noted that the appearance of the flame is not always a good indicator of combustion conditions. Flame colour and shape vary widely with the burner type and the fuel being burned. For this reason, visual observation should be used only by operators who are familiar with the operation of the combustion systems and always in conjunction with other testing methods.

Worksheet 5-2 is provided to assist in calculating combustion system efficiency using the indirect method. Use of the worksheet is illustrated in the following worked example.

A kiln burns natural gas at a rate of 10 x 10^6 Btu/h and operates at 1800°F when the ambient temperature is 70°F. The kiln is constructed of 9″ firebrick and measures 10 feet x 10 feet x 6 feet high.

Tests were conducted to determine the combustion system efficiency. The combustion air temperature was measured to be 90°F (32°C), the flue gas temperature was 660°F (349°C). An analysis of the flue gas showed it contains 2.5% oxygen (by volume) and 0.5% carbon monoxide.

Combustion System Efficiency Test
(Direct Method)
Worksheet 5-1

Company: ABC Co. Date: SEPT 14, 1988

Location: ANYTOWN By: MBEL

Equipment BOILER NO 1 Fuel Fired: NATURAL GAS

Rated Capacity: 50 000 KG/H Test No.: 1

Steam pressure	1500	kPa(abs)	
Feedwater temperature	102	°C	
Enthalpy of saturated/superheated steam	2790	kJ/kg	(1)
Enthalpy of saturated feedwater to boiler economizer	429	kJ/kg	(2)
Enthalpy of saturated liquid (boiler water)	845	kJ/kg	(3)
Heat absorbed/kg of steam (1) — (2)	2361	kJ/kg	(4)
Actual water evaporated	42500	kg/h	(5)
Rate of fuel firing (as-fired weight)$_a$	3294	kg/h	(6)
Fuel heating value (kJ/kg as-fired)$_b$	37520	kJ/kg	(7)
Total heat input (6) x (7)	123 590 880	kJ/h	(8)
Rate of boiler blowdown	1700	kg/h	(9)
Heat output in blowdown water (9) x [(3) − (2)]	707 200	kJ/h	(10)
Total heat output [(5) x (4)] + (10)	101 049 700	kJ/h	(11)
Direct efficiency $\frac{(11)}{(8)}$ x 100	81.8	%	

$_a$ use m^3/h for natural gas

$_b$ use kJ/m^3 for natural gas

Combustion System Efficiency Test
(Direct Method)
Worksheet 5-2

Company: XYZ Co Date: SEPT 14, 1988

Location: ANYTOWN By: MBEL

Equipment KILN Fuel Fired: NATURAL GAS

Rated Capacity: 10×10^6 BTU/h Test No.: 1

TEST DATA

Stack Temp.:	349 °C (1)	Combustion Air Temp.:	32 °C (2)
% O_2 in Flue Gas:	2.5 % (3)	% CO in Flue Gas:	0.5 % (4)
Excess Air$_a$:	12 % (5)	Dry Flue Gas Loss$_b$:	10.5 % (6)
Hydrogen Loss$_c$:	11.6 % (7)	Radiation Loss$_d$:	5.1 % (8)
Carbon Monoxide Loss$_e$:	1.3 % (9)	Unaccounted for Loss$_f$:	1 % (10)

COAL ONLY

Combustible Refuse Loss: ——— % (11)
(Appendix D, Figure 26)

Moisture Loss (Appendix D, Figure 25):
——— % (12)

TOTAL LOSSES

(Sum of (6) to (12)): 29.5 % (13)

INDIRECT EFFICIENCY = 100 − (13)

= 70.5 %

NOTES:
[a] Use the measured 0_2 % with Appendix D, Figure 1, 7, 13, or 19 (depending on fuel used) to determine excess air per cent.
[b] Use Appendix D, Figure 4, 10, 16, or 22 (depending on fuel used) to determine dry flue gas loss.
[c] Use Appendix D, Figure 6, 12, 18, or 24 (depending on fuel used) to determine hydrogen loss.
[d] Use Table 3 for furnaces, ovens and kilns and Table 4 for boilers.
[e] Use Appendix D, Figure 5, 11, 17 or 23 (depending on fuel used) to determine carbon monoxide loss.
[f] Usually 1%.

The outside surface area of the kiln is

$4 \times (10 \times 6) + (10 \times 10) = 340$ square feet

The per cent radiation heat loss for kilns is calculated using information from Table 3 and the following equation:

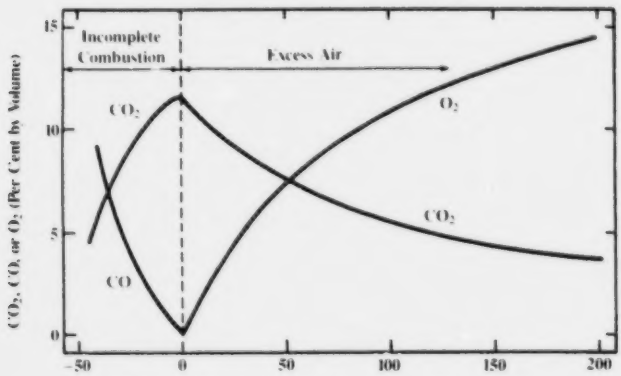
$$\frac{1151 \text{ Btu/(h·ft}^2\text{)} \text{ (Table 3)} \times 340 \text{ ft}^2}{10 \times 10^6 \text{ Btu/h}} \times 100 = 5.1\%$$

Combustion system efficiency using Worksheet 5-2 is calculated as 70.5%.

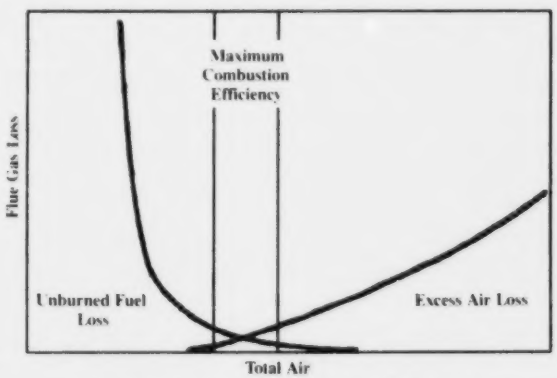
Optimization

Excess air Losses vs. Unburned Fuel Losses

The effects of excess air and the amount of combustibles in the flue gas are shown in Figure 6. It shows that in an ideal combustion system where fuel is well mixed with air and combustion is complete, no combustibles will be present. This condition is shown where the excess air is zero per cent. While this condition eliminates losses due to the loss of combustibles in the flue gas, too much excess air will of course increase flue gas losses. Figure 7 shows that there is an area of optimum air supply which is the best compromise between excess air losses and unburned fuel losses.



Effects of Excess Air on Flue Gas Composition
Figure 6



Zone of Maximum Combustion Efficiency
Figure 7

Temperature

The temperature of the flue gas is a good indicator of combustion system efficiency. Very high temperatures indicate that heat is not being transferred to the intended use and is being lost up the stack.

Combustion air should be introduced to the burner at as high a temperature as is practical. High temperatures promote the gasification and mixing of fuels, and also the extra energy available in the combustion air displaces an equivalent amount of fuel. For example, an extra 10 000 MJ/h added to the combustion air can displace 10 000 MJ/h of fuel use.

Air preheaters provide a way of increasing efficiency by transferring some of the heat from the flue gas to the combustion air. As a general rule, boiler efficiency will be increased by approximately 1% for every 25°C reduction in flue gas temperature.

Well Insulated Furnace Setting

Heat losses from the combustion chamber are a direct function of the level of applied thermal insulation. Excess heat losses may lead to the loss of combustibles up the stack by cooling the combustion chamber walls and reducing the rate of combustion. Insulation reduces heat losses from radiation and maintains outside surfaces at a temperature low enough for worker safety. If insulation is applied to a level where outside surfaces are safe to touch then it can be assumed the heat losses through the chamber walls have been reduced to a point where they are not significant.

Combustion Control Techniques

The simplest form of combustion control is to have the operator of a boiler, kiln, or oven manually adjust burner fuel and combustion air as the demand for heat changes and in response to secondary instrument readings

or alarms (Figure 8a.) This method of control is effective in applications where the demand for heat changes very little. Indeed there are probably many misapplications of highly automated combustion control systems that would benefit by reverting back to manual control or, at least, simple control.

Automated combustion control systems help to maximize combustion system efficiency by monitoring one, or several, combustion system parameters and using the information to control the flow of fuel and combustion air to the burner.

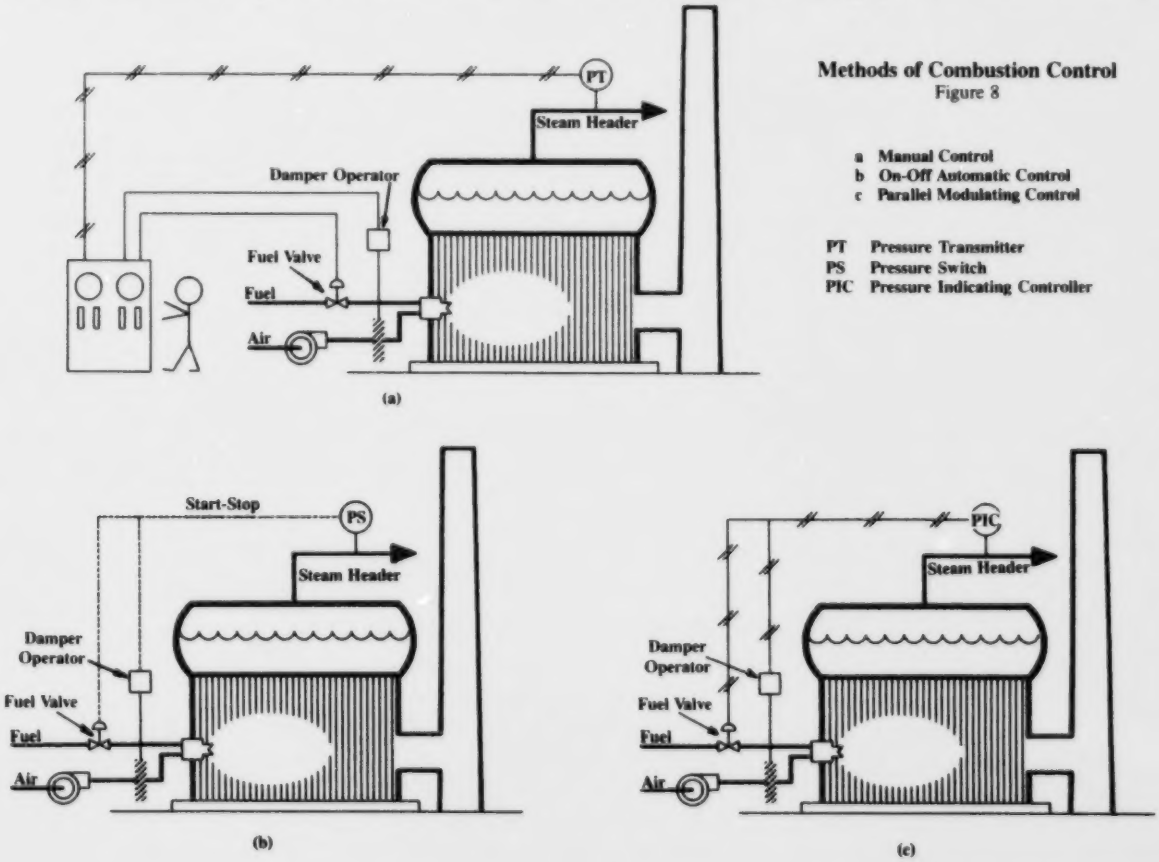
The most basic type of control cycles the burner on and off in response to the demand for heat (Figure 8b). The burner either operates at full rated capacity, or is off completely. This type of system installed on a boiler would monitor the steam header pressure, igniting the burner as the pressure drops below a predetermined setpoint and shutting it off when a second, higher setpoint is reached.

This is an inefficient method of control since the burner must counteract the cooling of heat exchange surfaces that occurs when the burner is off. The cooling is aggravated by a stack effect that draws cool air into the combustion chamber when the burner is off. To compensate for this and to provide heat as quickly as possible, the burner is always set up at a firing rate higher than would be required on a continuous basis.

A 3-position burner control system is used to partially overcome the disadvantages of the on-off type control system. With this system, the burner can be off, fully on, or at one intermediate firing rate. In this way the system is maintained at a more uniform temperature and can respond more readily to increased demand for heat.

The second type of combustion control is the *modulating system.* This system provides a better match between the demand for heat, and energy input by allowing the burner to continuously fire at any rate between minimum and maximum output as necessary to satisfy heat requirements. Modulating control systems generally fall into two categories; parallel, and metered systems.

Parallel modulating systems control a fuel valve and a combustion air damper in response to the demand for heat (Figure 8c). They are initially set up for a fuel/air ratio that provides for enough excess air to ensure that no control setting leads to the formation of combustibles in the flue gas. They cannot however detect and compensate for other variables which affect fuel/air ratios. These include changes in heating value of the fuel, combustion



Methods of Combustion Control
Figure 8

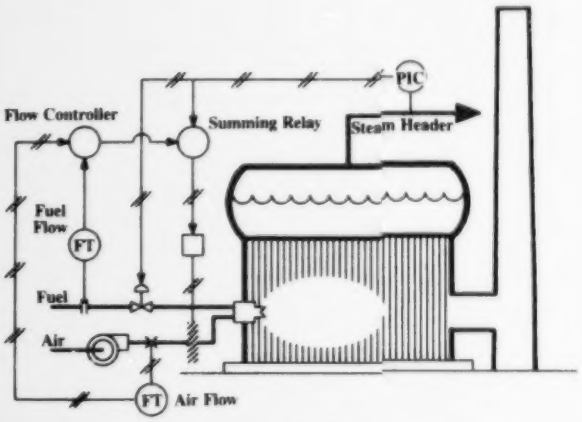
a Manual Control
b On-Off Automatic Control
c Parallel Modulating Control

PT Pressure Transmitter
PS Pressure Switch
PIC Pressure Indicating Controller

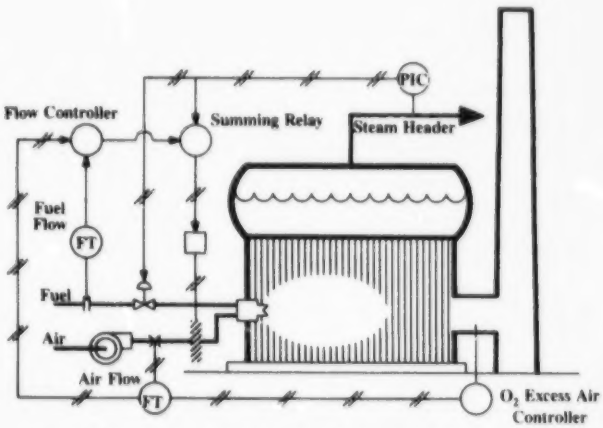
air temperature and humidity, mechanical wear in control linkages, changes in fuel supply pressure and other variables that affect fuel and combustion air flow. The effects of these factors can be overcome with an *excess air trim* system which fine tunes fuel/air ratios for optimum excess air. These are available as automatic or manual trim systems.

Metered, or cross limiting combustion control systems are a refinement of parallel systems, offering a higher degree of sophistication and efficiency (Figure 8d). As the burner firing rate is changed according to heat demand, the fuel/air ratios change according to a predetermined program. On a heat load increase, air flow leads fuel flow, and, on a load decrease, air flow lags fuel flow. In this way, combustibles are not allowed to form. Excess air trim capability can also be added to cross limiting systems to further enhance efficiency (Figure 8e).

Combustion control systems, can be quite sophisticated and should only be maintained and adjusted by personnel who are familiar with them. For maximum efficiency automated control systems should be checked and calibrated periodically to ensure they are providing good performance at the operating conditions most frequently encountered in normal operation.



Cross Limiting Control
Figure 8d



Cross Limiting Control With Excess Air Trim
Figure 8e

FT Flow Transmitter

Corrosion

The flue gas streams of practically all combustion systems contain potentially corrosive substances. The predominate sources of corrosion are sulphur oxides produced from fuels containing sulphur.

Sulphur oxidizes to form mostly sulphur dioxide (SO_2), however a small fraction oxidizes further to sulphur trioxide (SO_3). These gases combine readily with water vapor in the flue gas to form sulphurous and sulphuric acid (H_2SO_3 and H_2SO_4 respectively). In a gaseous state sulphur oxides will pass harmlessly through the breeching and stack. If however the acid vapor is cooled by contact with cool metal surfaces it may condense on the surface as liquid sulphurous acid and attack the metal. For a given mixture of gas and acidic vapors the highest temperature at which acid vapor condenses is called the *acid dewpoint.*

The corrosiveness of an acid increases as the concentration decreases. Thus, as the acid dewpoint of a system is reached the corrosive potential of the acid being formed is relatively low because it is very concentrated and is not being formed at a very high rate. As the surface temperature drops, acidic vapors condense at a higher rate and, as more water condenses, the acid becomes less concentrated. At some temperature, usually 10 to 25C° below the acid dewpoint there is a temperature at which the combination of acid condensation rate and concentration represents the maximum corrosion potential. This temperature may be determined by measuring the rate of acid buildup with an acid dewpoint meter and plotting the rate of acid buildup against temperature.

Safety Precautions

The products of incomplete combustion are fuel elements that have not had the opportunity to fully react because of insufficient combustion air, poor mixing or because the reaction was quenched by contact with a cold surface in the combustion chamber.

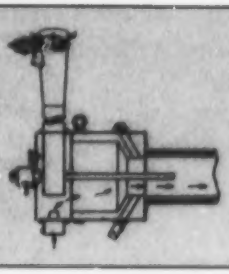
Carbon monoxide is a hazardous gas that can cause death if enough is inhaled. It is colorless and odorless, and concentrations as low as 1 per cent (10 000 parts per million) can be fatal. Air should be periodically analyzed for carbon monoxide in areas where it may be present.

Nitrogen oxides form when nitrogen in the combustion air reacts with oxygen. The compounds formed are nitrogen oxide (NO) and nitrogen dioxide (NO_2). They are found in the exhaust of most combustion systems but the amounts are significant only when the flame temperature is high. Exposure to nitrogen oxides produced in typical combustion processes will cause irritation of the eyes and mucous membranes.

Sulphur dioxide emissions are the result of burning fuel containing sulphur. Exposure to sulphur dioxide produces approximately the same effects as exposure to nitrogen oxides.

Aside from the danger of poisoning, the major concern in dealing with carbon monoxide is the danger of explosion. Natural gas, oil and pulverized coal combustion systems are required to have automatic burner management controls to shut down the system if no flame is present. Care should be taken to ensure that the equipment operates at safe CO concentrations and within limits specified by the Environmental Authorities.

EQUIPMENT SYSTEMS



There is a great variety of equipment that is commonly used to support combustion processes and to utilize the by-product energy forms. The combustion equipment used for boilers, furnaces, kilns, dryers and a variety of less common process applications have many principles and even design details in common. This section provides a review of the equipment used for the functions listed below:

- Fuel conditioning.
- Combustion air handling.
- Fuel/Air mixing.
- Combustion chamber.
- Heat transfer.
- Flue gas exhaust.
- Metering and control

Fuel Conditioning

Fuel conditioning takes different forms depending on the fuel and the equipment design. Conditioning of the fuel represents the steps taken to modify the fuel to make it usable or to enhance safety and performance characteristics. Conditioning techniques classified by fuel follow.

Natural Gas

Natural gas requires the least amount of user conditioning because it is not stored on-site and it is a clean fuel. The only form of conditioning typically required is to reduce the gas pressure to the equipment by means of a pressure reducing valve. This action may be employed to limit the energy input to equipment, to improve metering accuracy or to eliminate undesired pressure and flow fluctuations to the fuel burning equipment.

Oil

Different grades of oil require different forms of conditioning. Typically it is stored at the site and pumped to the point of use. Lighter oils such as No. 2 oil normally only require pressurization to transport the oil from storage to the oil burner and to atomize the oil at the burner. This facilitates good combustion by intimately mixing combustion air with the small droplets of oil leaving the burner.

No. 6 Bunker "C" oil requires several additional forms of fuel conditioning as listed below.

- Heating of the oil in the storage tank sufficiently to allow it to be pumped to the burner as required. Very often the oil is further heated in an oil pumping and heating set on the way to the burner. This assembly also contains duplex strainers to allow one to be cleaned as the oil is filtered through the other one.
- Pressure regulation is often required to maintain a constant supply pressure to the valve train ahead of the burner. The regulated oil pressure must be high enough to satisfy the maximum firing conditions. Typically this valve train includes a control valve which can vary the pressure of the oil to the burner according to the energy demand.
- Fuel oil additives are available, which change the character of the ash to facilitate removal by soot blowing. Two of the most effective additives are alumina and dolomite. The amount added should be roughly equal to the ash content of the fuel oil. The use of additives should be evaluated carefully with a reputable supplier and then checked in service with respect to performance and the financial benefit.
- Occasionally small quantities of water are purposely added to the oil to create an emulsion that can facilitate atomizing. This approach carries with it an energy loss element and should only be tried with the concurrence of the equipment manufacturer.

Coal

There are several forms of coal conditioning to achieve good combustion and these vary according to the type of coal burning equipment.

- Stoker fired systems require the least coal conditioning. The coal is cleaned, tramp metal is removed, and it is screened to eliminate oversized lumps.
- Pulverized coal fired installations require additional conditioning in the form of pulverizing the coal in a mill, transporting it to the burner in the combustion air stream and controlling the temperature of the fuel/air mixture by mixing hot and cold air.

Wood

Wood is able to absorb and retain a significant amount of water and so must be kept dry to improve the combustion efficiency. Wood is almost always burned in stoker fired installations and must therefore be reduced to smaller sized pieces.

Combustion Air Handling

Simple combustion systems use the effect of hot combustion gases rising in the stack to draw in combustion air. As the gases rise, a negative pressure is created in the combustion chamber and combustion air is sucked in. When all the energy needed to maintain the required flow of air and gas through the system is obtained by the use of a stack, the unit is said to operate on natural draft.

Frequently the stack is not relied on to provide the draft. In these cases mechanical forced or induced draft systems or both are used. The term *forced draft* denotes the movement of air through a combustion system by blowing it in through the combustion air inlet. This creates positive pressure in the chamber that forces combustion products out through the breeching to the stack.

Induced draft indicates the use of a fan in the breeching to draw gas out of the system by creating negative pressure in the combustion chamber. Combustion air can then be drawn in by the negative pressure or a forced draft fan can also be used with the two fans kept in balance by means of dampers in the flue gas outlet system.

Induced draft fans are usually located at the outlet of the final heat recovery stage. The fan must be able to handle high temperature combustion products and some particulates, depending on the fuel being burned.

Forced draft fans are usually positioned near the combustion air inlet and should be designed to overcome the resistance of the air ducts, air heater (if any), windbox and registers, burners or fuel bed and any other resistance between the fan and the furnace. The volume output must equal the maximum quantity of air required for combustion.

Centrifugal fans are normally used in combustion systems. These employ blades mounted on an impeller rotating within a spiral or volute housing. The design of the impeller blades determines the fan operating characteristics. Backward curved blades produce relatively low air velocities for a given impeller speed and forward curved blades give high velocities. Radial blade fans operate in between these two extremes. Refer to Module 13, Fans and Pumps in this series for a more detailed description of the operation of centrifugal fans.

The most important requirement for a fan is reliability. The fan will often operate continuously for long periods (up to a year or longer) without shutdown for repair or maintenance. To satisfy this condition the fan must have a rugged motor and housing and bearings that will not be heavily loaded during normal operation.

Sometimes the supply air ducting to the forced draft fan will have a venturi shaped section to provide a good combustion airflow measurement for the control system.

Fuel Burning Equipment

Fuel burning systems must provide several features to establish and sustain good combustion conditions.

1. Direct the fuel and air to the combustion chamber.
2. Atomize liquid fuels.
3. Initiate and maintain ignition.
4. Mix the fuel and air effectively.
5. Control the ratio of fuel to air.
6. Supply fuel and air in the quantities necessary to satisfy the heat load.

Oil and gas burners are generally premixed or diffusion types. The fuel and combustion air in a premixed burner are mixed and heated before ignition takes place. Fuel and air are introduced separately in a diffusion burner and mix and ignite upon exiting the burner. Most oil burners are diffusion types.

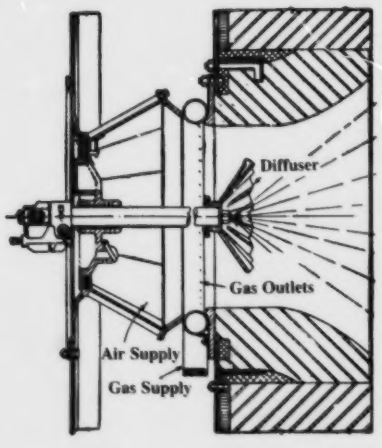
Natural Gas Burners

Burners for natural gas firing can be divided into low and high pressure types. This classification is derived from the gas pressure required to provide satisfactory operation. Low pressure burners usually operate at gas pressures between 1.7 and 27.6 kPa. Low pressure gas burners can be classified as premix and nozzle mix types. In premix burners, the gas and combustion air are mixed together before entering the burner. One of the most common premix burners consists of a manifold containing a series of small ports. This type of burner is suitable for low temperature applications such as make up air heating, drying ovens, baking ovens, food roasters and deep fat vats.

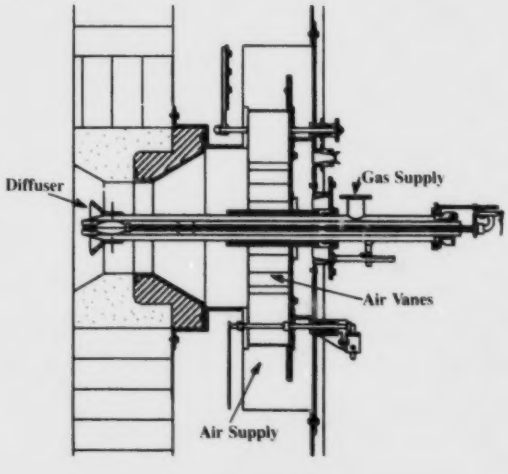
Nozzle mixing burners, as the name implies, do not allow the fuel and air to mix until they leave the ports of the burner. Nozzle mixing burners come in a variety of configurations and are used in high temperature applications.

Larger industrial burners operate at higher gas pressures. Mixing of gas and combustion air also occurs after the gas leaves the burner. They are generally classified into three main types.

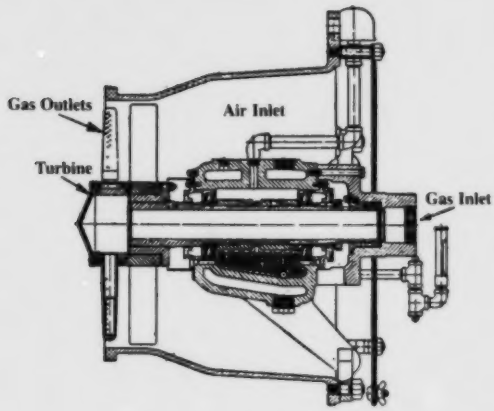
1. *Gas ring* burners have a circular gas manifold around the throat of the burner. A series of orifices around the inner surface of the ring sprays gas into the stream of combustion air flowing through the throat as shown in Figure 9.
2. The *centre diffusion* type burner has a gas header with orifices located at the centre of the burner (Figure 10). A diffuser plate at the gas tip assures prompt and steady ignition as well as intense mixing of the fuel and air. Complete combustion can be obtained with approximately 7 per cent excess air. Adjustable dampers in the burner windbox induce rotation of the air as it flows through the burner.
3. *Turbine* type gas burners use revolving instead of fixed orifices to distribute gas transversely to the air stream while rotating at high speed (Figure 11). The energy in the gas under pressure is used to perform the mechanical mixing and proportioning of the gas with the air for combustion. An integral fan driven by the revolving orifices delivers the necessary air for combustion, which flows at right angles to the streams of gas discharged from the orifices. Very good mixing of the fuel and air makes it possible to complete combustion with excess air quantities as low as 5 per cent. Turbine type burners have no visible flame when properly operated. They have a high turndown ratio and the installation cost is low because forced draft fans and ductwork are eliminated.



Gas Ring Burner
Figure 9



Center Diffusion Gas Burner
Figure 10



Turbine Type Gas Burner
Figure 11

Oil Burners

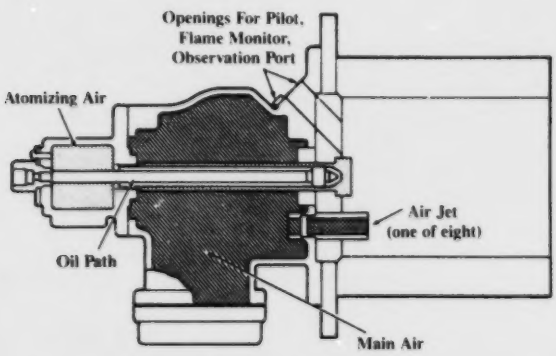
All fuel oils must be vaporized before they will burn. This must be done in two stages, atomization and vaporization. A stream of oil is broken up into tiny particles when it is atomized. This exposes the maximum possible surface area of oil to the combustion air. Exposure to heat from combustion, or an ignitor, vaporizes the oil freeing the combustible elements to participate in the combustion reaction.

Low Pressure Air Atomizing Burners

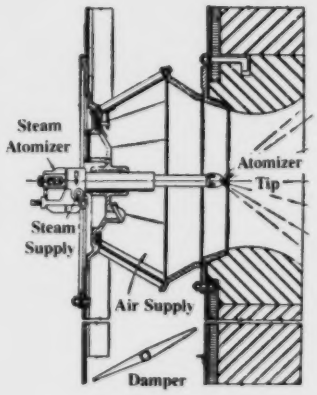
Low pressure air atomizing burners use large quantities of air at approximately 7 to 14 kPa as the oil atomizing medium. A well designed atomizing unit may use only 10% of the total combustion air for atomizing. Oil pressure at the burner is usually 7 to 35 kPa (Figure 12).

High Pressure Air or Steam Atomizing Burners

High pressure air or steam atomizing burners use steam or compressed air to tear droplets of oil from a stream and propel them into the combustion chamber (Figure 13). The high velocity of the oil particles through the air produces the friction necessary for quick vaporization. These burners are capable of vaporizing the heaviest fuel oils and are often used for incinerating liquid wastes. Vaporizing steam or compressed air is used at pressures ranging from 35 to 1035 kPa. Steam consumption may vary from 0.1 to 0.7 kg per litre of oil (approximately 0.5 to 4 per cent of the steam produced) and air consumption from 0.16 to 0.74 m^3 per litre depending on the design and size of the atomizer and the oil viscosity.



Low Pressure Air Atomizing Burner
Figure 12



High Pressure Air or Steam Atomizing Burner
Figure 13

Mechanical Oil Pressure Atomizing Burners

When oil is permitted to expand through a small orifice it breaks into a spray of fine droplets. This is the principle used in *oil pressure atomizers* which are usually designed to operate with oil pressures of approximately 680 kPa (see Figure 14).

Turndown is poor on this type of nozzle because of the need to maintain high oil pressures. These burners have the lowest initial and operating costs, but relatively high maintenance costs and poor turndown restricts their use.

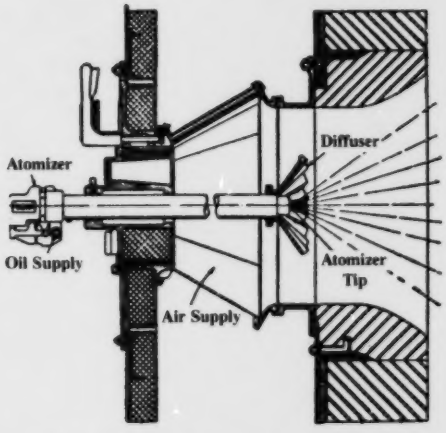
Low Excess Air Burners

Low excess air burners are designed to burn oil with as little as 3 per cent excess air. These burners require more powerful forced draft fans because their design restricts the flow of air somewhat and combustion control equipment must be more sophisticated than that used in conventional burners in order to maintain low excess air conditions.

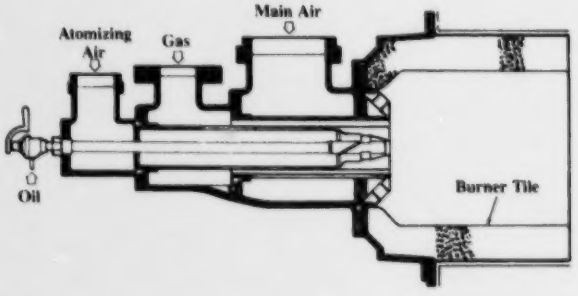
Dual Fuel Burners

Periodic changes in the fuel supply such as those encountered with interruptible natural gas contracts necessitate the ability to easily switch to another fuel. Burners that effectively burn more than one fuel are called *combination or dual fuel burners* (see Figure 15).

One fuel is often burned as the primary source of heat in this system. The other fuel (usually oil) is kept available as a back up in the event the primary fuel supply is interrupted.



Mechanical Oil Pressure Atomizing Burner
Figure 14



Dual Fuel Burner
Figure 15

Solid Fuel Burning

Solid fuel burners can be characterized according to the size of fuel particles they burn. *Pulverized coal burners* use coal that has been ground to particles the size of talcum powder (approximately 100 microns) while grate units use larger chunks.

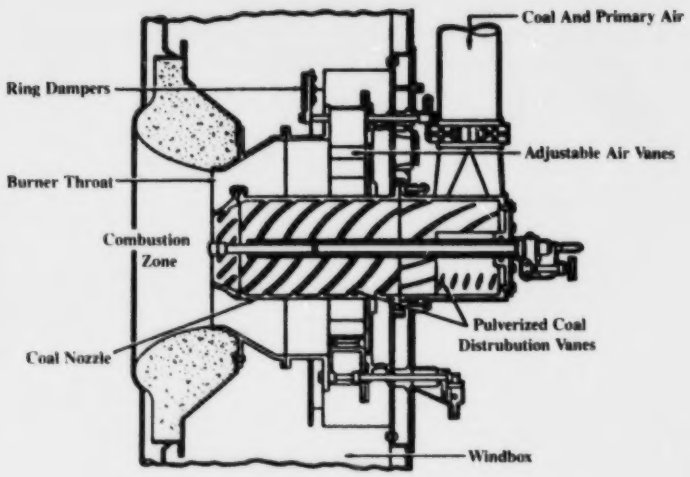
Pulverized Coal Burners

Pulverized coal can be transported in an air stream and burned in burners that resemble a tall, narrow slot. The shape of the resulting coal stream gives greater exposure to the combustion air, resulting in rapid ignition and complete combustion.

Pulverized coal may also be burned in a cyclone combustor (Figure 16). Cyclone burners provide long residence times for the fuel which ensures complete combustion of difficult fuels such as low quality coal or waste material.

Grate Firing

Burning solid fuels on a grate does not require a high degree of pulverization. The fuel must merely be reduced to a uniformly small size. The main components of a grate-type combustor are the *stoker* which supplies fuel to the furnace and the *grate* on which the fuel burns.

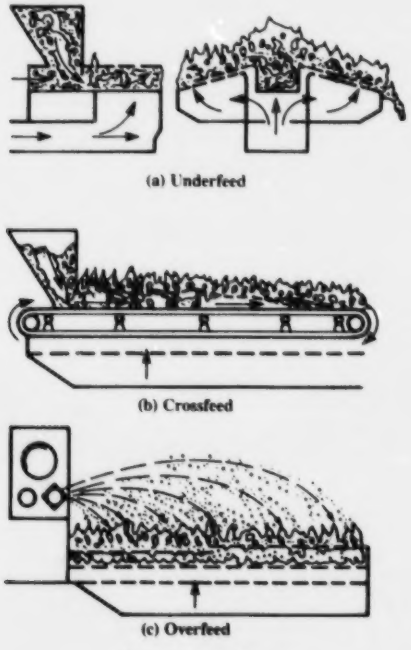


Cyclone Combustor For Coal
Figure 16

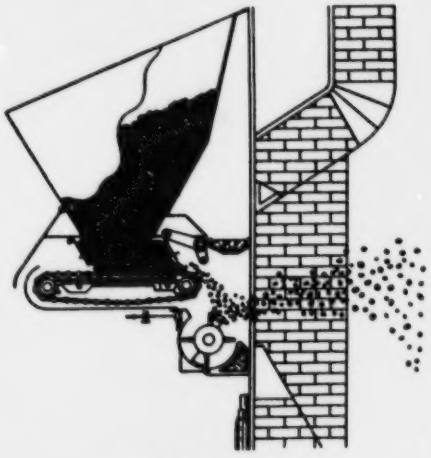
The major types of stokers are *underfeed, overfeed, crossfeed* (Figure 17) *or spreader.* Spreader stokers (Figure 18) are the most commonly used and can burn a wide range of fuels.

Grates used in conjunction with the stokers can be stationary (either horizontal or inclined), moving (as an endless belt) or vibrating. The choice of feeder and grate combination depends on the fuel characteristics, size of unit and load response requirements. Adjustments, such as grate speed, are made to suit the fuel characteristics and thermal demand.

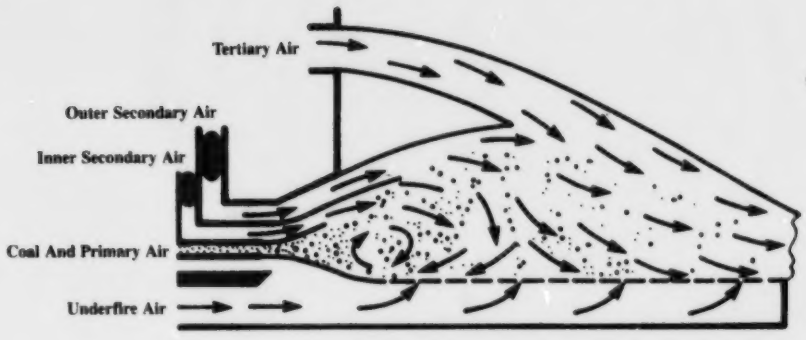
Combustion air is supplied from a point below the grate. As the fuel burns volatile gases are given off. A second and sometimes third stream of overfire air is injected above the grate to burn these gases and release further heat (Figure 19).



Types of Stokers
Figure 17



Spreader Stoker
Figure 18



Over- and Under-Fire Air Supply For Grate Firing
Figure 19

Fluidized Bed Firing

Fluidized bed combustion has become an increasingly attractive way of burning solid fuels for several reasons. First it can burn high sulphur fuels in an environmentally acceptable manner. Also, by operating at lower temperatures, the process results in lower emissions of NO_x as well as being less likely to experience slagging problems.

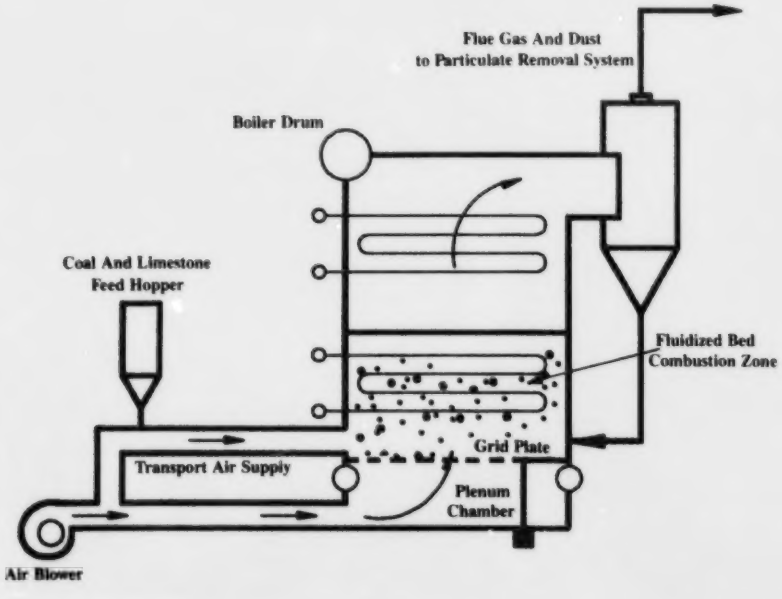
In a fluidized bed combustor, combustion air is blown up from underneath a bed of solid fuel granules. The bed then behaves like a fluid, creating high turbulence and mixing as bubbles of air flow through the bed (see Figure 20). This provides excellent contact between the fuel and air and results in complete and rapid combustion. Granular limestone is often mixed with the fuel to neutralize acids as they are formed.

Combustion Chambers

The combustion chamber provides a controlled environment where the combustion reactions can take place. By shape and size the chamber ensures that combustion is complete before gases are allowed to exit. The chamber generally consists of simple refractory brick walls, with or without insulation. The walls may also be water cooled, bare or covered with refractory and insulation, and with or without a steel casing.

Exhaust Breeching and Stack

The breeching and stack allow the passage of flue gases out of the combustion chamber. An induced draft fan may be mounted in the breeching downstream of all flue gas heat recovery equipment.



Fluidized Bed Combustor
Figure 20

Heat Transfer

Heat Transfer to Boiler Tubes

The purpose of a steam or hot water boiler is to transfer energy released in the combustion process to the boiler tubes. The amount of heat transfer surface is a design judgement based on recovered energy and capital cost. Heat transfer is enhanced by maintaining clean boiler tube surfaces.

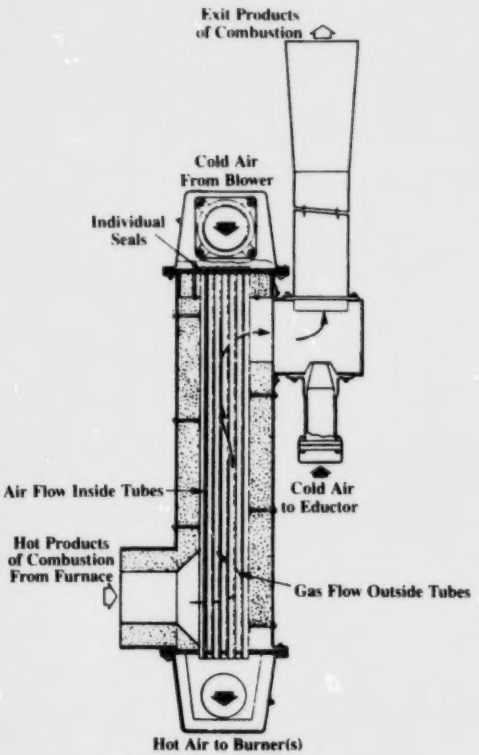
- Internally the tubes are kept clean with good water treatment.
- Externally the tubes are kept clean by maintaining good combustion conditions and soot blowing. It is significant to note that the heat conductivity loss increases from less than 10 per cent to more than 50 per cent as the soot builds up from slightly less than 1 mm to just over 3 mm.

Air Preheaters

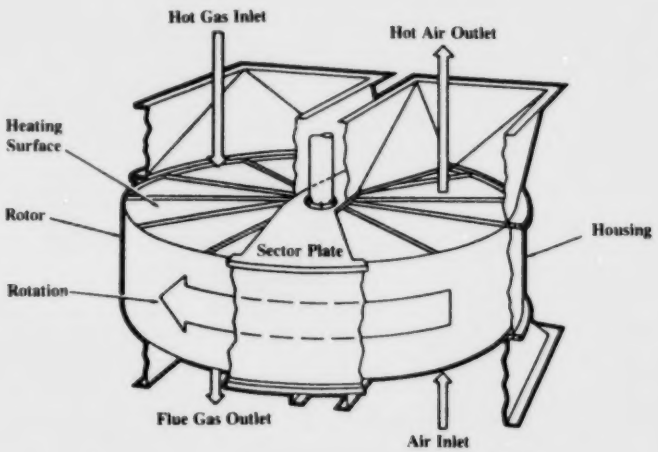
Air preheaters heat the combustion air before it enters the combustor. This aids in proper atomization and vaporization of liquid fuels. Preheating is usually accomplished by transferring heat from the hot flue gases through a heat exchanger to the combustion air. Two of the most common air preheaters are tubular recuperative and regenerative types.

Recuperative air heaters (Figure 21) are shell and tube heat exchangers where hot flue gases flow through the tubes and combustion air flows around the tubes inside the shell. The forced draft fan forces the air through the shell and the stack draft or induced draft fan draws the flue gases through the tubes.

Regenerative preheaters operate by alternately heating and cooling a heat storage medium. The most widely used regenerative preheaters consist of a large wheel that rotates slowly through both the flue gas and combustion air streams (Figure 22). Leakage from one stream to the next is prevented by using seals around the passage in which the wheel rotates. The wheel is made of porous material that can capture and store a large amount of heat as the flue gas passes through it. Upon leaving the hot gas stream the heated wheel immediately rotates into the combustion air stream where stored energy is transferred to the cooler air. Cooled sections of the wheel continuously revolve back into the hot gas stream to continue the process.


Exit Products of Combustion
Cold Air From Blower
Individual Seals
Air Flow Inside Tubes
Cold Air to Eductor
Hot Products of Combustion From Furnace
Gas Flow Outside Tubes
Hot Air to Burner(s)

Recuperative Air Preheater
Figure 21



Regenerative Air Preheater
Figure 22

Twin Bed Regenerative Burner System

A recent, promising development is the integral burner/regenerator, called the Twin Bed Regenerator (Figure 23). The system consists of two identical burners, each having an enclosed bed of a solid heat storage medium through which the combustion air passes. One burner fires while the inactive burner serves as the flue for the operating burner, and stores heat in the bed. Within 20 seconds the firing burner will have withdrawn most of the stored heat from its bed of heat storage "nuggets" in the process of preheating the combustion air. A sequencer then flips fuel, air and flue gas valves to their alternate positions and lights the other burner whose storage bed is now very hot. In this way combustion air temperatures can be raised to temperatures approaching that of the flue gas and combustion efficiency is greatly improved.

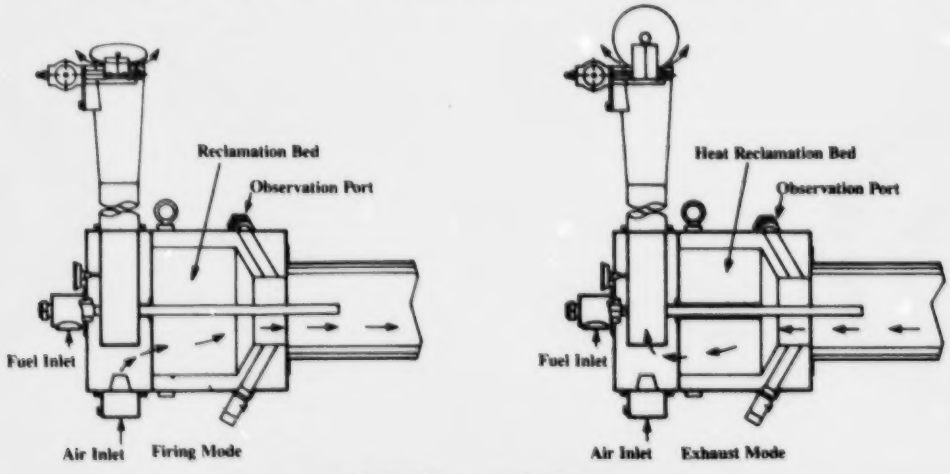
Radiation Burners

Radiation burners should be used when radiation heat transfer is to be enhanced or when flame contact with the product is to be avoided. Radiation burners heat the surrounding refractory tile by convection from combustion gases thrown sideways from the burner. The hot refractory surfaces then radiate heat to the furnace load. Where true radiant heating is desired, it is important that the hot gases have no final velocity in a direction toward the work to be heated (see Figure 24).

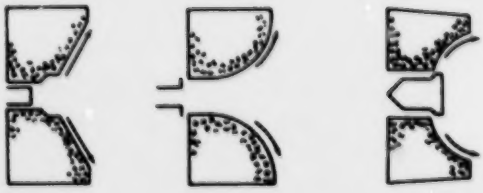
Long Luminous Flame Burners

In some operations direct flame radiation over a large area is desirable. This is frequently the case in extremely long furnaces where conventional short flames would give poor heat distribution or where all burners must be located at one end.

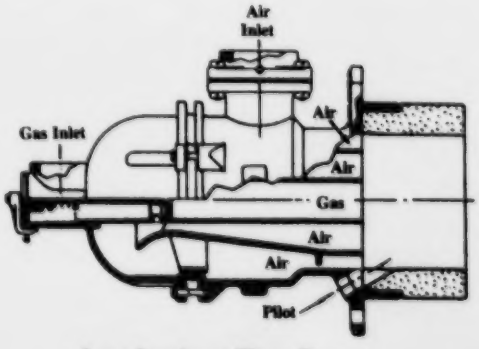
Long flames can be produced if the rate of mixing of the gas and air is very low so that the two fluids travel a considerable distance from the burner before complete mixing and burning occurs (Figure 25).



Twin Bed Regenerative Burner
Figure 23



Types of Radiation Burners
Figure 24



Long Luminous Flame Burner
Figure 25

Environmental Equipment

Air Pollution Control Equipment

These systems are designed to reduce fly ash (particulates), sulphur oxide and nitrous oxide emissions from the plant. The degree of treatment is influenced by government environmental regulations. Pollution control equipment is not usually required on small burners firing natural gas or oil. All solid fuel firing equipment will require at least one of the following types of pollution control equipment.

- *Mechanical cyclone collectors* (dust collectors) remove particulates by centrifugal and gravitation forces developed in a vortex separator. Their use is now limited to small stoker-fired units because of low efficiency of collecting very small particles.
- *Electrostatic precipitators* electrically charge suspended particles in the gas and then attract them to collecting plates with an electric field. The collecting plates are then rapped to cause the particles to drop into hoppers. Precipitators can be designed for a high collecting efficiency of 98 per cent or more.
- *Fabric filters, or baghouses*, have a long history of applications in dry and wet filtration processes to recover chemicals or control stack emissions. The dirty gas is passed through fabric filters with the particulate matter forming a cake on the fabric. The deposit is periodically removed from the filter by mechanically shaking the fabric, or by a pulse of air. Fabric filters can be designed for collecting 99 per cent of particulates or more.
- *Lime or limestone scrubbing* is the oldest method of removing sulphur dioxide from flue gas. The flue gas enters a venturi scrubber and contacts an injected absorbent lime slurry. The flue gas then passes through a vertical spray tower where the slurry and absorbed sulphur compounds are washed. All items of pollution control equipment use varying amounts of electrical energy that significantly increase the energy used per plant output. It is imperative that operation and maintenance staff keep this equipment in good working order.

Avoiding Dewpoint Conditions

Care must be taken to ensure that conditions are not created that could lead to water vapor condensation in the stack or breeching. This can result from heat recovery equipment that removes too much heat from the flue gas, or operating a burner at the low fire position of its turndown range. Flue gas temperatures after all stages of heat recovery should be monitored to ensure that acid dewpoint temperatures are not reached. The acid dewpoint temperature in a natural gas fired system is approximately 56°C.

It should be noted that a flue gas condensing system reduces the flue gas temperature below the dewpoint to recover substantial energy. However, the materials in this type of system are carefully selected to protect against acid dew point corrosion.

Measurement Devices

Flue Gas Analysis

The fuel/air ratio and degree of completeness of combustion are most accurately estimated from an analysis of the flue gas. A regular flue gas monitoring program is vital to maintaining good combustion efficiency. Regular analysis can provide the necessary information to properly adjust burners for correct combustion.

The methods of monitoring fall into two categories, batch or spot monitoring and continuous monitoring. Batch methods of flue gas analysis involve capturing a sample of gas and then analyzing it on the spot or in a laboratory. The most widely used instrument is the *Orsat*. The Orsat is relatively simple and inexpensive. A sample of the flue gas is bubbled successively through a series of solutions that selectively absorbs the oxygen, carbon monoxide and carbon dioxide flue gas components. The sample volume decreases as each of the component gases is absorbed by one of the solutions. The amount by which the sample volume decreases indicates the amount of that gas in the original sample.

In continuous analysis methods, instruments designed to measure certain flue gas components are connected to sensors installed in the flue gas path. A common arrangement of sensors measures O_2 or CO_2 for excess air and then CO or total combustibles. The advantage of using continuous analyzers is that they provide an immediate and continuous indication of combustor operation. They are subject to interference from other flue gas constituents such as particulates and must be cleaned and calibrated periodically.

Temperature

The temperature of the flue gas gives the operator an indication of the effectiveness of the equipment system.

External heat recovery equipment installed in the flue gas stream can be assessed by measuring the temperature drop across both sides of the heat exchanger.

Abnormally high temperatures in the breeching may indicate too much excess air. The cause of abnormally low temperatures after the last heat recovery stage should be checked to avoid acid condensation conditions which could lead to corrosion problems.

Temperature monitoring systems usually consist of a number of sensors installed in the flue and combustion air streams linked by wires to a remote indicator. Refer to Module No. 15, Measuring, Metering, and Monitoring, in this series, for more information on temperature sensors and measurement.

Flow

Measurements of flow in a combustion system are necessary to determine system efficiency and performance. Fuel flow and the relative flow of combustion air are common measurements. Absolute measurements of air volume are rarely needed. Boiler systems also require the measurement of steam (or hot water) and feedwater flow.

The flow of steam is most often measured with a flow meter that uses an orifice plate installed in the steam header pipe as the sensor. Orifice plates are precisely machined devices which, with differential pressure sensing devices, can accurately measure steam and gas flow, to about 25 per cent of maximum capacity. A pitot tube flowmeter is sometimes used to measure the relative flow of combustion air. Fuel oil flow is often measured with a positive displacement type flowmeter such as a rotating vane meter. The operation and use of these flowmeters is described in more detail in Module No. 15, Measuring, Metering and Monitoring.

Combustion Control

Combustion control systems of the type described in the Fundamentals section require several components which measure existing conditions, process the information from the sensor and control the process in response to the measured variables. This equipment ultimately adjusts the firing rate by controlling the flow of fuel and combustion air into the burner.

Jack shaft actuators control the fuel valve and air dampers in parallel to maintain a consistent fuel/air ratio over the operating range. The jack shaft mechanism consists of an actuator that rotates a shaft. Arms attached to the shaft move rods which in turn move a control lever on the valve or damper. The actuator itself responds to an electric, hydraulic or pneumatic control signal generated by the system controller.

Separately positioned air and fuel valves are used in more sophisticated control systems. Each valve is controlled by an actuator which responds to an electric, hydraulic or pneumatic control signal. This independence of operators, combined with characterizing cams etc., allows greater precision in the control of fuel/air ratios, to maintain minimum excess air.

ENERGY MANAGEMENT OPPORTUNITIES

Energy Management Opportunities is a term that represents the ways that energy can be used wisely to save money. A number of typical Energy Management Opportunities, subdivided into Housekeeping, Low Cost, and Retrofit categories, are outlined in this section to illustrate potential energy savings. This is not a complete listing of the available opportunities. It is intended to provide ideas for management, operating and maintenance personnel to identify other opportunities that are applicable to a particular facility.

It must be stressed once again that many of the opportunities outlined in this section should be implemented only after consultation with trained specialists and regulating authorities.

Housekeeping Opportunities

Implemented housekeeping opportunities are energy management actions that are done on a regular basis and never less than once a year. This includes activities such as efficient operation, regular maintenance and troubleshooting.

Operation

1. Condition fuel for improved combustion.
2. Minimize load swings to make more efficient fuel-air ratios achievable.
3. Regularly monitor the excess air.
4. Regularly check the combustion efficiency.
5. Regularly monitor and compare secondary performance related data.
6. Manage boiler loading to achieve the highest plant efficiency.

Maintenance

1. Keep burner assemblies in proper adjustment.
2. Maintain tightness of air ducts and flue gas breeching.
3. Replace observation or access doors, and repair leaking door seals.
4. Check for "hot spots" that may indicate deteriorating refractory and/or insulation that should be repaired during the annual shutdown period.
5. Keep fireside surfaces clean.
6. Replace or repair missing or damaged insulation.
7. Overhaul the seals of regenerative airheaters.

Operation Examples

1. Proper fuel conditioning procedures must be maintained and for different fuels this includes the actions listed below.
   - Natural Gas — Ensure that the supply pressure is maintained at the value used in setting up the burner controls and gas flow meter.
   - Oil — Ensure that the fuel is properly filtered and that oil pressure and temperature conditions are maintained consistent with those used in setting up the burner and metering systems. For heavy oil systems the atomizing steam must also be maintained at conditions consistent with the set-up by a burner specialist.
   - Coal — Ensure that the size conditioning of the coal as well as the related combustion air volumes and temperatures are consistent with the conditions established by equipment specialists.
   - Wood — Don't expose wood to precipitation during storage.

2. Schedule steam and hot water demand or the throughput of process kilns and ovens to minimize load swings. The combustion controls can be adjusted for the more efficient combustion conditions if the load swings are moderate.
3. Check the flue gas constituents regularly and determine the excess air from this data. High excess air or carbon monoxide conditions should be avoided by adjusting the fuel burning equipment and/or the combustion controls.
4. Regular calculations of combustion efficiency is an extension to the previous point, and helps to provide perspective on the cost of fuel utilization inefficiencies. The indirect losses method is recommended for calculating efficiency.
5. Secondary measurements such as combustion air and flue gas pressures (positive and negative), fan capacities, gas and oil burner settings, and burner register settings etc. should all be monitored and compared to set-up conditions.
6. It is common to have two or three boilers operating simultaneously. By knowing the boiler load and efficiency profile for each boiler it is possible to optimize the operation without cost. The firing of one boiler relative to others can often be biased through the combustion control system. An even more efficient arrangement might be to normally baseload all but one boiler which will modulate according to thermal demand. If plant load variations permit this, it is possible to operate the manually fired boilers at the optimum load range with the lowest possible excess air to further improve the combined efficiency.

Maintenance Examples

The following maintenance items should be performed on a regular basis, and never less than once a year. They should be considered to be part of a planned preventive maintenance program. The frequency of maintenance will depend on the nature of the facility and equipment.

1. *Burner assemblies including combustion air registers etc. should be checked and adjusted regularly by an experienced person.* After the burners have been adjusted, the operators should observe the flame to establish a basis of understanding for future visual comparison.
2. *Leakage of flue gas may cause hazardous operating conditions.* All flue gas breeching should be inspected regularly, and leaks repaired immediately. If an induced draft fan is used, the breeching downstream will be pressurized and leaks will result in the gas discharging to the plant. Leaks on the upstream side will draw air in and increase the load on the fan.
3. *Combustion air ducting should be inspected and all leaks repaired.* Leakage of air out of the air ducts will impose an extra load on the forced draft fan.
4. Leakage of air or gas around observation or access doors will create the same problems as described in the foregoing Examples 2 and 3. An open furnace door will also cause considerable radiation heat loss and there is a danger that furnace pressurization could cause hot gas to be ejected through the opening creating a safety hazard.
5. *Hot spots on the skin of a furnace or boiler are an indication of excessive heat loss from areas where insulation is damaged or missing.* Surface temperatures should not exceed 50°C. Missing or damaged refractory and/or insulation should be replaced to reduce heat loss and to maintain a safe, comfortable work place.
6. *The fire side of all oil and coal fired heat exchanger surfaces must be kept clean* with frequent soot blowing.
7. *The seals on regenerative air preheaters should be overhauled regularly.*
8. *A common cause of deteriorating combustion system efficiency is operation at needlessly high excess air levels.* If the combustion control system is not operating properly there is a tendency to increase the airflow to ensure that the fuel/air ratio will be safe for load changes or upset conditions. A properly operating control system will permit operation at the lowest attainable excess air while maintaining proper combustion during load changes. Typically a 10% reduction in the excess air will increase efficiency by 1.5%.

Low Cost Opportunities

Implemented low cost opportunities are energy management actions that are done once and for which the cost is not great. This creates a separation from the housekeeping activities which must be repeated regularly.

Some of the potential low cost energy saving opportunities are listed below.

1. Install performance monitoring equipment.
2. Relocate combustion air intake.

3. Add insulation.
4. Modify air delivery system.
5. Modify fuel delivery system.
6. Upgrade combustion controls.

Low Cost Examples

1. Install Performance Monitoring Equipment

Performance monitoring instruments are necessary to identify inefficient operating conditions and potential problems. The minimum instrumentation should allow the operator to determine energy input and output values. Fuel flow meters should be installed for each furnace, kiln, or boiler to identify consumption. Flue gas temperature and gas analysis should be used to determine the flue gas energy loss. If a preheater is used to recover heat from the flue gas, temperature of gas and air in and out should be used to check performance.

2. Relocate Combustion Air Intake

Combustion system efficiency will improve if the combustion air temperature is increased. The air intake can sometimes be located at the top of the plant to use warmer air that collects there.

Example: A kiln fires natural gas and uses 10 000 kg/h of air at an average temperature of 20°C. The measured air temperature at the ceiling of the plant was 35°C. A duct was installed to draw the combustion air from this warm location. The specific heat of the air is 1.01 kJ/kg·°C.

Heat recovered = 10 000 kg/h x (35-20)°C x 1.01 kJ/kg.°C.

= 151 500 kJ/h

The kiln operates 6000 hours per year and natural gas costs $4.25/GJ.

$$\text{Annual fuel savings} = \frac{151\ 500 \times 6000 \times 4.25}{10^6} = \$3{,}863$$

The cost to supply and install the ducting is $9,000

$$\text{Simple payback} = \frac{\$9{,}000}{\$3{,}863} = 2.3 \text{ years}$$

3. Add Insulation

Add insulation to areas previously left uninsulated or increase thickness, where economical, in areas already insulated. Energy management was not a major concern to boiler and furnace operators 15 to 20 years ago. For this reason worker protection was often the main objective when insulating equipment. Some areas out of reach of operating staff were not insulated at all. These areas should receive at least the minimum economic thickness of insulation. Note that additional refractory or firebrick is always added to the interior of the combustion chamber to protect the equipment shell. Refer to Module No. 1, Process Insulation, in this series, for guidance in determining the economic thickness of insulation.

4. Modify Air Delivery System

Burner requirements vary but must be satisfied. Radiant burners require adequate turbulence for good mixing of fuel and air but relatively low air velocity so there is minimal forward motion of flue gases as they leave the burner area. Long luminous flame burners require relatively high velocity air with very little turbulence in order to lengthen the zone where fuel and air will mix and ignite. The windbox and burner air registers must be adjusted carefully in order to achieve these special conditions.

5. Modify Fuel Delivery System

Oil pressure atomizing burners require oil pressures of approximately 680 kPa for proper atomization. Insuffi-

cient pressure results in soot and the loss of combustibles up the stack. The same result occurs if heavy fuel oils are not adequately heated.

6. Upgrade Combustion Controls

Combustion control systems should be inspected regularly to ensure that all actuators and linkages are operating smoothly through the full range of motion. This equipment should be overhauled or replaced if the operation is not correct.

Many existing control systems, while satisfying thermal demand, may not provide the tight control necessary to keep excess air at a minimum to provide maximum efficiency. These systems may benefit from the addition of a flue gas monitoring and excess air trim system.

Retrofit Opportunities

Implemented retrofit opportunities are energy management actions which are done once and for which the cost is significant. This section provides a few examples of how the installation of new equipment can contribute to the saving of energy dollars. Retrofit projects usually involve significant technical changes to a process. For this reason it is suggested that the equipment manufacturer or a consulting engineering firm be retained to make an evaluation of the proposed changes. Retrofit opportunities are listed below.

1. Install air preheater.
2. Upgrade burner or install new burner.
3. Convert from oil to gas.
4. Install a new combustion control system.
5. Install regenerative burners.

Retrofit Examples

1. Install Air Preheater

Preheating combustion air aids in the atomization and vaporization of fuels. The heat added to the air also results in a reduction of fuel consumption roughly equal to heat added.

The burner manufacturer should be consulted to determine the maximum air temperature the burner can tolerate. This may be as low as 250°C and it is unlikely to be higher than 400°C since alloy steel construction rather than carbon steel would be required.

Installing a heat exchanger in the flue gas stream will increase the pressure drop in the flue gas system, reducing the air throughput capacity. It may be necessary to install a new fan or impeller and drive motor to maintain the original capacity. Because of these and other possible complications, it is suggested that the furnace manufacturer or a consulting engineering firm be retained to evaluate the proposed changes.

The example that follows is based on the installation of an air preheater for a gas fired tank in a glass plant. The system operated 50 weeks of the year and the annual gas savings for melting and holding the glass were 4438 GJ. The cost of natural gas was $4.25/GJ.

$$\text{Annual dollar savings} = 4438 \text{ GJ} \times \$4.25/\text{GJ}$$

$$= \$18{,}862$$

The cost of the recuperator and installation was $20,000.

$$\text{Simple payback} = \frac{\$20{,}000}{\$18{,}862} = 1.1 \text{ years}$$

2. Upgrade Burner or Install New Burner

The installation of a modern burner could permit lower excess air operation, thus reducing stack losses. A new burner assembly can also be the means to provide full automation for start-up and shut-down. In a multiple burner installation automation can permit automatic start-up and shut-down of burners according to load. This reduces the modulating range of the burners to allow operation at higher fuel pressures.

Provision must be made to shut off the combustion air to idle burners. This reduces losses due to excess air entering the furnace and not taking part in the combustion process.

3. Convert From Oil to Gas

The conversion of fuels such as from oil to natural gas does not necessarily save energy. However, it can result in substantial savings where there are potential savings in terms of dollars per gigajoule of fuel.

Example: A boiler rated at 10 000 kg/h burns No. 2 oil which costs $0.30/L. Annual oil consumption is 2.2 million litres. The cost to convert to natural gas is estimated to be $120,000, including a new burner assembly, modified controls, gas piping and installation labour. The boiler operates at 40% excess air and the flue gas temperature is 240°C. The cost of the proposed natural gas is $4.25/GJ.

Conversion from oil to gas firing means that the boiler efficiency will be reduced from 80 to approximately 77.3% due to the higher water vapor content in the flue gases which result from the combustion of hydrogen in the gas.

From Appendix D, Fig. 10 the dry flue gas loss at 40% excess air and 240°C flue gas temperature for No. 2 oil firing is 11%. The hydrogen loss is 7% (see Appendix D, Fig. 12). Radiation and unmeasured losses are approximately 2%. Thus,

Boiler efficiency $100 - (7 + 11 + 2) = 80\%$

From Appendix D, Fig. 4 the dry flue gas loss for natural gas at the same excess air and flue gas temperature is 10%, and the hydrogen loss from Appendix D-6 is 10.7%. Radiation and unmeasured losses are the same 2%.

Boiler efficiency for gas $= 100 - (10 + 10.7 + 2)$

$= 77.3\%$

Annual Oil Cost $= \$0.30 \times 2.2 \times 10^6$ litres
$= \$660{,}000$

The annual cost of pumping the oil is $5,000 making the total annual cost $665,000.
No. 2 oil has a heating value (Appendix C) of 38.68 MJ/L.

$$\text{Annual oil energy} = \frac{2.2 \times 10^6 \text{ L/y} \times 38.68 \text{ MJ/L}}{1000 \text{ MJ/GJ}}$$

$= 85\ 096$ GJ

Total energy input per year when burning gas will be higher owing to the lower burner efficiency.

$$\text{Annual gas energy} = 85\ 096 \text{ GJ} \times \frac{80}{77.3} = 88\ 068 \text{ GJ/y}$$

Annual gas cost $= 88\ 068$ GJ/y x $4.25/GJ $= \$374{,}289$

Annual savings $= \$665{,}000 - \$374{,}289$

$= \$290{,}711$

$$\text{Simple payback} = \frac{\$120{,}000}{\$290{,}000} = 0.41 \text{ years (5 months)}$$

Further savings could be realized by reducing the excess air from 40% to 10% with a better gas burner.

4. New Combustion Control System

It is sometimes possible to make substantial fuel savings by upgrading combustion controls.

A system which operates fuel and air controls in parallel with no feedback from measured fuel and air flows

or flue gas analysis will normally operate with higher values of excess air. The addition of flow sensing devices and a fuel/air ratio feedback will give closer control under varying load conditions, permitting operation at lower excess air.

The addition of oxygen trim control of air flow, compensates for variations in fuel and combustion air and permits further reductions in excess air. It should be noted that flue gas analyzers require regular maintenance and calibration. In this respect the probe type, which is located directly in the gas stream is generally more reliable than types which draw a continuous sample from the flue gas system.

The reduction in excess air that results from the installation of an improved control system can lead to substantial energy savings.

Install Regenerative Burners

The retrofitting of regenerative burners can significantly reduce energy requirements because of the very high combustion air temperatures that can be obtained.

Example: A continuous roller-hearth heat treatment furnace in a steel plant was retrofitted with eight pairs of regenerative natural gas burners as part of a refurbishment program. As a result of the retrofit, the temperature of the preheated combustion air increased from 200 to 700°C. Fuel consumption was reduced by nearly 50%, and annual energy savings were 60 000 000 MJ. The total estimated cost of the project was $675,000 with projected annual savings of $400,000.

$$\text{Simple payback} = \frac{\$675{,}000}{\$405{,}000} = 1.7 \text{ years}$$

APPENDICES

A — GLOSSARY OF TERMS

B — TABLES

C — COMMON CONVERSIONS

D — COMBUSTION SYSTEM HEAT LOSS GRAPHS

E — WORKSHEETS

GLOSSARY APPENDIX A

Air Infiltration — The leakage of air into a combustion chamber, duct or breeching.

Adiabatic Temperature — The theoretical temperature of a flame if all of the energy is used to heat the products of combustion and none is lost to the surroundings.

Ambient Temperature — The temperature of air surrounding the equipment.

Ash-Free Basis — A method of determining the heating values of different coals that compensates for the variation in ash content from one grade to another.

Atomizer — A device which reduces a liquid to a fine spray.

Audit, Diagnostic — The analysis of a potential opportunity to save energy which could involve the assessment of the current process operation and records, calculation of savings, and estimates of capital and operating costs so that the financial viability of the project can be established.

Audit, Walk Through — The visual inspection of a facility to observe how energy is used or wasted.

Axial Fan — Fans that move air by the change in velocity of the air passing over the impeller blades. There is no energy added by centrifugal forces.

Base Load — Base load is the term applied to a boiler load that excludes the variable load.

Breeching — A duct which transports the products of combustion between the combustion chamber and the stack.

Burner — A device which introduces the fuel and air into a furnace at the desired velocities and turbulence to maintain proper combustion.

Burner Windbox — A plenum chamber around a burner in which the air pressure is sufficiently high to ensure proper delivery of air to the burner.

Carbon Loss — The loss of combustibles in the form of carbon particles from a combustion system. The particles are carried up the stack suspended in the flue gas.

Casing — A metal covering used to enclose a boiler.

Centrifugal Fan — A fan that moves air by the centrifugal force that is produced by moving the air between the rotating impeller blades, and by the inertia generated by the velocity of the air leaving the impeller.

Combustibles — The heat producing constituents of a fuel.

Combustible Loss — The unliberated thermal energy loss from unburned combustible matter.

Combustion — The rapid chemical combination of oxygen with the combustible elements of a fuel resulting in the production of heat.

Combustion Rate — The quantity of fuel fired per unit of time.

Complete Combustion — The complete oxidation of all the combustible constituents of a fuel.

Control Valve — A valve used to control the flow of fuel or water.

Damper — A variable resistance device for regulating the flow of air or flue gas.

Delayed Combustion — Combustion that takes place at a greater distance from the burner than is desired, usually because of improper mixing of the fuel and combustion air. This can lead to insufficient heat transfer to the product and/or slag deposits on heat transfer surfaces.

Dew Point — The temperature at which condensation begins when cooling air or gas.

Draft — The difference between atmospheric pressure and some lower pressure existing in the furnace or gas passages of a boiler.

Dry Gas — That portion of flue gas which contains no water vapor.

Dry Gas Loss — The loss representing the difference between the heat content of the dry exhaust gases and their heat content at the temperature of ambient air.

Efficiency — The ratio of output to the input. The efficiency of a boiler is the ratio of the heat absorbed by water and steam to the heat in the fuel fired.

Energy Management Opportunities (EMO), Housekeeping — Potential energy saving activities which should be done on a regular basis and never less than once per year. This includes preventive maintenance programs.

Energy Management Opportunities (EMO), Low Cost — Potential energy saving improvements that are done once and for which the cost is not considered great.

Energy Management Opportunities (EMO), Retrofit — Potential energy saving improvements that are done once and for which the cost is significant.

Enthalpy — Enthalpy is a measure of the heat energy per unit mass of steam. Units are expressed as kJ/kg.

Excess Air — Air supplied for combustion in excess of that theoretically required for complete oxidation.

Flame Detector — A safety device used to sense the presence of a flame in a burner. Fuel to the burner is shut off if no flame is detected in a burner that should be firing. This prevents the accumulation of unburned fuel in the combustion chamber.

Flue Gas — The gaseous products of combustion.

Forced Draft Fan — A fan supplying air under pressure to the fuel burning equipment.

Fuel-Air Ratio — The ratio of the mass or volume, of fuel to air.

Furnace Draft — The draft in a furnace.

Gas Analysis — The determination of the constituents of the flue gas.

Gasification — The process of heating a solid fuel so that its combustible constituents are released as a gas, making them available to be burned.

Heating Surface — Heating surface is the area of heat exchange surfaces which receive heat from the products of combustion.

Higher Heating Value — The amount of heat recovered when the products of complete combustion of a unit quantity of fuel are cooled to the initial temperature of the fuel and air.

Ignition Temperature — The temperature above which the energy released by the combustion of a given fuel is greater than the energy required to support the reaction.

Induced Draft Fan — A fan exhausting hot gas from the heat absorbing equipment.

Insulation — A material of low thermal conductivity used to reduce heat losses.

Lower Heating Value — The higher heating value minus the latent heat of vaporization of the water vapor in the products of combustion.

Mechanical Atomizing Oil Burner — A burner which uses the pressure of the oil for atomization.

Multiple Burner — An installation that is comprised of more than one burner. Used to provide even heat transfer over a large area.

Oxidation — A chemical reaction where an element combines with oxygen molecules to form a compound that is an oxide of the original element, e.g. carbon combines with oxygen to form carbon dioxide.

Perfect Combustion — The complete oxidation of all the combustible constituents of a fuel, utilizing all the oxygen supplied.

Precipitator — An ash separator and collector of the electrostatic type.

Products of Combustion — The gases, vapors, and solids resulting from the combustion of fuel.

Quenching — The stifling of a combustion reaction through contact with a cool surface that reduces the temperature of the fuel-air mixture to a point below the ignition temperature.

Radiation Loss — A term used to account for the conduction, radiation, and convection heat losses from the boiler settings to the ambient air.

Reducing Atmosphere — An environment, lacking in oxygen, that is conducive to the occurrence of reduction reactions (the opposite of oxidation).

Register — The apparatus used in a burner to regulate the direction of combustion air flow.

Scrubber — The apparatus for the removal of solids and gases from flue gas by entrainment in water, or a chemical solution.

Smoke — Small gas borne particles of carbon or soot, resulting from incomplete combustion.

Sootblower — A mechanical device for discharging steam or air to clean heat absorbing surfaces.

Stack — A vertical "duct", which due to the difference in density between the internal hot gas and external air creates a draft at the base.

Steam Atomizing Oil Burner — A burner for firing oil which is atomized by steam.

Theoretical Air — The quantity of air required for perfect combustion. Also called stoichiometric air.

Total Air — The total quantity of air supplied for combustion expressed as a percentage of theoretical air.

Unaccounted-for-Losses — That portion of a boiler heat balance which represents the difference between 100 per cent and the sum of the heat absorbed by the unit and all the classified losses expressed as a per cent.

Unburned Combustible — The combustible portion of the fuel which is not completely oxidized.

APPENDIX B

COMMON COMBUSTION REACTIONS
TABLE 1

Substance	Formula	Molecular Weight	Reaction	Heat of Combustion (MJ/kg)
Carbon	C	12.01	$2C + O_2 = 2CO$ $C + O_2 = CO_2$	9.21 32.79
Carbon Monoxide	CO	28.01	$2CO + O_2 = 2CO_2$	10.1
Hydrogen	H_2	2.016	$2H_2 + O_2 = 2H_2O$	142.07
Sulphur	S	32.06	$S + O_2 = SO_2$	9.26
Methane	CH_4	16.04	$CH_4 + 2O_2 = CO_2 + 2H_2O$	55.51
Ethhane	C_2H_6	30.07	$2C_2H_6 + 7O_2 = 4CO_2 + 6H_2O$	51.9
Propane	C_3H_8	44.09	$C_3H_8 + 5O_2 = 3CO_2 + 4H_2O$	50.36
Natural Gas	*	**	***	44.4_a
No. 2 Oil	*	**	***	45.3_a
No. 6 Oil	*	**	***	42.7_a
Bituminous Coal	*	**	***	30.7_a
Sub-Bituminous Coal	*	**	***	24_a
Lignite	*	**	***	17_a
Wood	*	**	***	19_a

* Consists mainly of hydrocarbons; composition varies
** Molecular weight varies with composition
*** Combustion of carbon, hydrogen, and sulphur but the amounts of each are difficult to determine without an analysis of the fuel
$_a$ Heat of combustion will vary with composition

USUAL AMOUNT OF EXCESS AIR SUPPLIED TO FUEL BURNING EQUIPMENT
TABLE 2

Fuel	Type of Furnace or Burners	Excess Air % by Weight
Pulverized Coal	Completely water-cooled furnace for slag-tap or dry ash removal	15 - 20
	Partially water-cooled furnace for dry ash removal	15 - 40
Crushed Coal	Cyclone furnace — pressure or suction	10 - 15
Coal	Spreader stoker	30 - 60
	Water-cooled vibrating grate stoker	30 - 60
	Chain grate and travelling grate stokers	15 - 50
	Underfeed stoker	20 - 50
Fuel Oil	Oil burners, register type	5 - 10
	Multifuel burners	10 - 20
Natural gas, coke oven and refinery gas	Register type burners	5 - 10
	Multi-fuel burners	7 - 12
Wood	Dutch oven (10-23% through grates) and Hofft-type	20 - 25
Black liquor	Recovery furnaces for kraft and soda-pulping processes	5 - 7

HEAT LOSS AND TEMPERATURE OF REFRACTORY WALLS
BASED ON 0.95 SURFACE EMMITANCE
10 FPS AIR AT 70°F
TABLE 3

	surf. temp.	1200	1600	1800	2000	2200	2400	2600	2900
4 ½"fb + 2"bi_1	heat loss	326	464	537	617	706			
	surf. temp.	144	175	195	201	218			
4½"fb + 4½"ib_{23}	heat loss	239	349	408	469	537	606		
	surf. temp.	126	147	161	177	190	201		
9"fb	heat loss	949	1315	1511	1703	1903	2107	2313	
	surf. temp.	261	323	349	379	404	432	459	
4½"fb_{30} + 4½"ib_{23}	heat loss	187	273	320	370	402	480	542	642
	surf. temp.	114	133	143	154	165	180	190	208
9"ib_{23}	heat loss	139	206	242	281	323			
	surf. temp.	105	118	126	134	144			
4½"fb + 4½"ib_{23} + 2"bi_2	heat loss	139	199	230	263	298	333		
	surf. temp.	105	117	123	132	137	145		
13½"fb	heat loss	662	920	1052	1188	1322	1462	1605	
	surf. temp.	214	256	277	298	322	343	363	
9"ib_{30} + 4½"ib_{23}	heat loss	142	207	242	280	320	361	406	480
	surf. temp.	105	119	126	134	143	152	162	180
9"ib_{23} + 4½"ib_{16}	heat loss	88	131	154	182	208			
	surf. temp.	92	103	107	114	119			
9"fb + 4½"ib_{23} + 2"bi_3	heat loss	115	175	209	244	282	325	368	
	surf. temp.	99	110	117	126	132	142	153	
9"ib_{30} + 9"ib_{23}	heat loss	95	138	162	188	215	243	274	325
	surf. temp.	94	105	109	115	120	126	133	144
6"pr	heat loss	813	1230	1431	1637	1850	2074		
	surf. temp.	246	310	337	367	399	428		
6"pr + 2" bi_1	heat loss	277	397	460	529	461	676		
	surf. temp.	133	159	176	186	200	213		
6"dc	heat loss	777	1089	1248	1411	1578	1750	1928	2199
	surf. temp.	235	287	309	335	361	384	406	443
6"dc + 2"lc_1	heat loss	205	314	375	440	509	580	656	776
	surf. temp.	118	141	155	169	184	197	209	235

table continues on next page

		1200	1600	1800	2000	2200	2400	2600	2900
$6''lc_2$	heat loss	1159	1511	1671	1823	1967	2102	2236	2454
	surf. temp.	295	350	374	397	415	432	446	478
$6''lc_2 + 2''bi_2$	heat loss	229	305	343					
	surf. temp.	123	139	147					
$6''cf_1$	heat loss	77	138	175	216	262			
	surf. temp.	89	104	111	120	130			
$6''cf_1 + 2''bi_2$	heat loss	71	121	151	182	216			
	surf. temp.	88	100	107	113	120			
$2''cf_2 + 9''fb$	heat loss	257	443	556	679	808	943	1085	
	surf. temp.	129	171	193	214	237	262	284	
$2''cf_1 + 9''ib_{26}$	heat loss	129	205	248	294	344			
	surf. temp.	102	118	127	137	148			
$1''cf_3 + 4½''ib_{26} + 4½''ib_{20}$	heat loss	88	134	160	190	219	248		
	surf. temp.	92	103	108	115	121	127		
$2''cf_4 + 4''bi_2$	heat loss	117	210	266					
	surf. temp.	95	114	126					

Heat loss: Btu/h·ft^2 surface temperature: °F

fb = firebrick, Harbison-Walker 2600 F Superduty Alamo
ib_{30} = insulating brick, APGreen 3000 F Greenlite-30
ib_{23} = insulating brick, Babcock & Wilcox 2300 F K-23
ib_{16} = insulating brick, Babcock & Wilcox 1600 F K-1620
bi_1 = block insulation, Johns-Manville 2000 F Superex diat.
bi_2 = block insulation, Johns-Manville 1600 F Superex Ca-Si
bi_3 = block insulation, Johns-Manville 1500 F Banrock mineral wood
pr = plastic refractory, Plibrico Super F
dc = dense castable, APGreen 3000 F Mizzou
lc_1 = light castable APGreen 1600 F black mix
lc_2 = light castable, APGreen 3300 F Greencast 97 L
cf_1 = ceramic fiber, B & W 2300 F Kaowool, 12 lb/ft^3
cf_2 = ceramic fiber, Carborundum 2600 F Fiberfrax H
cf_3 = ceramic fiber, Imperial Chem. Ind. (B & W) 3000 F Saffil
cf_4 = ceramic fiber, JM 2300 F Cerablanket, 6 lb/ft^3

Blank sections indicate maximum material temperatures have been exceeded.

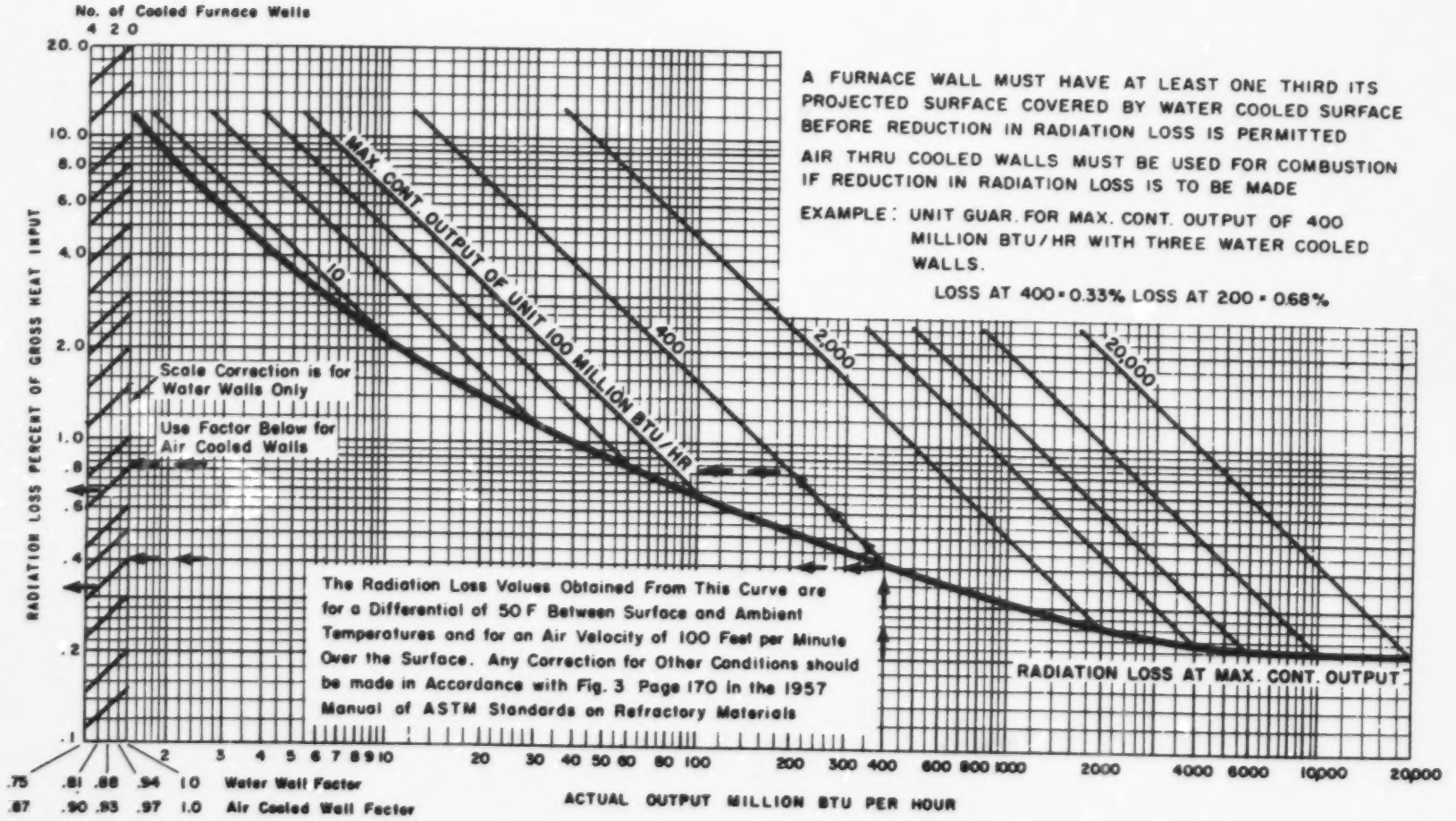
To calculate the per cent surface heat loss for Worksheet 5-1 for ovens, furnaces and kilns use the following equation.

$$\text{Heat loss \%} = \frac{\text{Heat loss (Table 4) x Wall area (ft}^2\text{)}}{\text{Firing Rate}\left(\frac{\text{Btu}}{\text{h}}\right)} \times 100$$

Where, the wall area is the outside surface area of the kiln, oven, or furnace.

Reproduced from: *North American Combustion Handbook*

RADIATION HEAT LOSS FROM BOILER WALLS
TABLE 4


No. of Cooled Furnace Walls
4 2 0
RADIATION LOSS PERCENT OF GROSS HEAT INPUT
20.0
10.0
8.0
6.0
4.0
2.0
1.0
.8
.6
.4
.2
.1
MAX. CONT. OUTPUT OF UNIT 100 MILLION BTU/HR
10
400
2,000
20,000
Scale Correction is for Water Walls Only
Use Factor Below for Air Cooled Walls
A FURNACE WALL MUST HAVE AT LEAST ONE THIRD ITS PROJECTED SURFACE COVERED BY WATER COOLED SURFACE BEFORE REDUCTION IN RADIATION LOSS IS PERMITTED
AIR THRU COOLED WALLS MUST BE USED FOR COMBUSTION IF REDUCTION IN RADIATION LOSS IS TO BE MADE
EXAMPLE: UNIT GUAR. FOR MAX. CONT. OUTPUT OF 400 MILLION BTU/HR WITH THREE WATER COOLED WALLS.
LOSS AT 400 = 0.33% LOSS AT 200 = 0.68%
The Radiation Loss Values Obtained From This Curve are for a Differential of 50 F Between Surface and Ambient Temperatures and for an Air Velocity of 100 Feet per Minute Over the Surface. Any Correction for Other Conditions should be made in Accordance with Fig. 3 Page 170 in the 1957 Manual of ASTM Standards on Refractory Materials
RADIATION LOSS AT MAX. CONT. OUTPUT
2 3 4 5 6 7 8 9 10 20 30 40 50 60 80 100 200 300 400 600 800 1000 2000 4000 6000 10000 20000
ACTUAL OUTPUT MILLION BTU PER HOUR
.75 .81 .88 .94 1.0 Water Wall Factor
.87 .90 .93 .97 1.0 Air Cooled Wall Factor

RANGE OF ANALYSES OF FUEL OILS
TABLE 5

	Weight Per Cent	
	No. 2 Oil	No. 6 Oil
Sulphur	0.15 - 1.0	0.7 - 3 5
Hydrogen	11.8 - 13.9	9.5 - 12.0
Carbon	86.1 - 88.2	86.5 - 90.2
Nitrogen	0.0 - 0.1	—
Oxygen	—	—
Ash	—	0.01 - 0.5
Water & Sediment (volume %)	0.0 - 0.1	0.05 - 2.0
Heating Value (MJ/1)	38.68	40.5

TYPICAL ANALYSES OF WOOD (DRY)
TABLE 6

	Carbon	Hydrogen	Oxygen	Nitrogen	Ash	Higher Heating Value* (MJ/kg)
SOFTWOODS						
Cedar, White	48.8	6.37	44.46	—	0.37	19.5
Fir, Douglas	52.3	6.3	40.5	0.1	0.8	21.0
Pine, Pitch	59.0	7.19	32.68	—	1.13	26.3
White	52.55	6.08	41.25	—	0.12	20.7
Yellow	52.6	7.02	40.07	—	1.31	22.3
HARDWOODS						
Ash,White	49.73	6.93	43.04	—	0.30	20.7
Beech	51.64	6.26	41.45	—	0.65	20.4
Birch, White	49.77	6.49	43 45	—	0.29	20.1
Elm	50.35	6.57	42.34	—	0.74	20.5
Hickory	49.67	6.49	43.11	—	0.73	20.2
Maple	50.64	6.02	41.74	0.25	1.35	19.9
Oak, Black	48.78	6.09	44.98	—	0.15	19.0
Red	49.49	6.62	43.74	—	0.15	20.2
White	50.44	6.59	42.73	—	0.24	20.5
Poplar	51.64	6.26	41.45	—	0.65	20.7

*Calculated from reported higher heating value of kiln-dried wood assumed to contain 8 percent moisture.

ANALYSES OF TYPICAL CANADIAN COALS
TABLE 7

PROVINCE Seam or Mine	Weight %										Moisture and Ash-Free Basis
	Proximate Analysis				Ultimate Analysis						
	Moist.	V.M.*	F.C.*	Ash	C	H	O	N	S	MJ/kg	MJ/kg
NOVA SCOTIA											
Brad d'Or	5.3	32.2	50.7	11.8	65.7	4.2	6.5	1.2	5.3	27.9	33.7
Springhill	2.8	29.9	57.6	9.7	73.6	4.8	5.5	2.0	1.6	30.8	35.1
Stellarton	2.5	29.1	54.8	13.6	72.3	4.6	4.5	1.9	1.0	29.4	35.1
Joggins	5.0	32.9	43.1	19.0	56.2	3.9	7.2	1.1	7.6	24.6	32.3
Westville	2.5	24.6	53.8	19.1	67.2	4.2	3.8	1.8	1.4	27.3	34.8
NEW BRUNSWICK											
Minto	3.2	29.7	47.8	19.3	62.7	4.1	2.3	0.8	7.6	26.9	34.8
Bothwell	3.0	29.8	49.6	17.6	64.8	4.3	1.6	0.8	7.9	27.5	34.6
SASKATCHEWAN											
Souris	35.0	26.0	33.0	6.0	43.0	2.9	12.0	0.7	0.4	17.2	29.1
Taylorton	35.0	26.2	32.6	6.2	42.8	2.9	12.0	0.7	0.4	17.1	29.1
ALBERTA											
Round Hill	28.5	27.2	39.1	5.2	50.2	3.3	11.4	1.0	0.4	19.4	29.3
Cascade	1.5	13.2	78.1	7.2	82.9	3.9	2.3	1.5	0.7	32.6	35.7
Coalspur	8.9	31.9	45.6	13.6	60.2	4.1	11.9	0.9	0.3	24.1	31.0
Crows Nest	2.5	24.9	57.8	14.8	71.8	4.3	4.9	1.1	0.62	9.10	35.1
Drumheller	18.2	30.7	44.2	6.9	56.8	3.7	12.7	1.2	0.5	22.8	30.4
Edmonton	25.5	27.4	40.2	6.9	50.4	3.2	12.5	1.1	0.4	20.0	29.6
Lethbridge	10.2	35.3	44.4	10.1	62.2	4.4	10.9	1.6	0.6	25.3	31.8
Mountain Park	2.5	27.2	57.6	12.7	73.7	4.5	5.0	1.2	0.4	30.2	35.7
Nordegg	1.5	15.3	71.4	11.8	78.5	4.0	2.4	1.2	0.6	31.5	36.3
BRITISH COLUMBIA											
Crows Nest	1.5	24.0	66.0	8.5	79.1	4.7	4.2	1.4	0.6	32.4	36.0
Nanaimo	5.0	34.6	46.1	14.3	66.3	4.7	8.0	1.3	0.4	27.5	30.6
Comox	3.5	31.5	51.4	13.8	69.1	4.5	5.7	1.0	2.4	29.7	35.9
Nicola Valley	8.0	33.9	43.3	14.8	61.8	4.5	8.9	1.5	0.5	25.6	33.2

*NOTE:
V.M. volatile material
F.C. fixed carbon

APPENDIX C

COMMON CONVERSIONS

1 barrel (35 Imp gal) (42 US gal)	= 159.1 litres
1 gallon (Imp)	= 1.20094 gallon (US)
1 horsepower (boiler)	= 9809.6 watts
1 horsepower	= 2545 Btu/hour
1 horsepower	= 0.746 kilowatts
1 joule	= 1 N-m
Kelvin	= (°C + 273.15)
1 kilowatt	= 3600 kilojoules
1 Newton	= 1 kg-m/s^2
1 therm	= 10^5 Btu
1 ton (refrigerant)	= 12002.84 Btu/hour
1 ton (refrigerant)	= 3516.8 watts
1 watt	= 1 joule/second
Rankine	= (°F + 459.67)

Cubes

1 yd^3	= 27 ft^3
1 ft^3	= 1728 in^3
1 cm^3	= 1000 mm^3
1 m^3	= 10^6 cm^3
1 m^3	= 1000 L

Squares

1 yd^2	= 9 ft^2
1 ft^2	= 144 in^2
1 cm^2	= 100 mm^2
1 m^2	= 10000 cm^2

SI PREFIXES

Prefix	Symbol	Magnitude	Factor
tera	T	1 000 000 000 000	10^{12}
giga	G	1 000 000 000	10^9
mega	M	1 000 000	10^6
kilo	k	1 000	10^3
hecto	h	100	10^2
deca	da	10	10^1
deci	d	0.1	10^{-1}
centi	c	0.01	10^{-2}
milli	m	0.001	10^{-3}
micro	u	0.000 001	10^{-6}
nano	n	0.000 000 001	10^{-9}
pica	p	0.000 000 000 001	10^{-12}

UNIT CONVERSION TABLES
METRIC TO IMPERIAL

FROM	SYMBOL	TO	SYMBOL	MULTIPLY BY
amperes/square centimetre	A/cm^2	amperes/square inch	A/in^2	6.452
Celsius	°C	Fahrenheit	°F	(°C × 9/5) + 32
centimetres	cm	inches	in	0.3937
cubic centimetres	cm^3	cubic inches	in^3	0.06102
cubic metres	m^3	cubic foot	ft^3	35.314
grams	g	ounces	oz	0.03527
grams	g	pounds	lb	0.0022
grams/litre	g/L	pounds/cubic foot	lb/ft^3	0.06243
joules	J	Btu	Btu	9.480×10^{-4}
joules	J	foot-pounds	ft-lb	0.7376
joules	J	horsepower-hours	hp-h	3.73×10^{-7}
joules/metre, (Newtons)	J/m, N	pounds	lb	0.2248
kilograms	kg	pounds	lb	2.205
kilograms	kg	tons (long)	ton	9.842×10^{-4}
kilograms	kg	tons (short)	tn	1.102×10^{-3}
kilometres	km	miles (statute)	mi	0.6214
kilopascals	kPa	atmospheres	atm	9.87×10^{-3}
kilopascals	kPa	inches of mercury (@ 32°F)	in Hg	0.2953
kilopascals	kPa	inches of water (@ 4°C)	in H_2O	4.0147
kilopascals	kPa	pounds/square inch	psi	0.1450
kilowatts	kW	foot-pounds/second	ft-lb/s	737.6
kilowatts	kW	horsepower	hp	1.341
kilowatt-hours	kWh	Btu	Btu	3413
litres	L	cubic foot	ft^3	0.03531
litres	L	gallons (Imp)	gal (Imp)	0.21998
litres	L	gallons (US)	gal (US)	0.2642
litres/second	L/s	cubic foot/minute	cfm	2.1186
lumen/square metre	lm/m^2	lumen/square foot	lm/ft^2	0.09290
lux, lumen/square metre	lx, lm/m^2	footcandles	fc	0.09290
metres	m	foot	ft	3.281
metres	m	yard	yd	1.09361
parts per million	ppm	grains/gallon (Imp)	gr/gal (Imp)	0.07
parts per million	ppm	grains/gallon (US)	gr/gal (US)	0.05842
permeance (metric)	PERM	permeance (Imp)	perm	0.01748
square centimetres	cm^2	square inches	in^2	0.1550
square metres	m^2	square foot	ft^2	10.764
square metres	m^2	square yards	yd^2	1.196
tonne (metric)	t	pounds	lb	2204.6
watt	W	Btu/hour	Btu/h	3.413
watt	W	lumen	lm	668.45

4138T/T33(-4)

UNIT CONVERSION TABLES
IMPERIAL TO METRIC

FROM	SYMBOL	TO	SYMBOL	MULTIPLY BY
ampere/in^2	A/in^2	ampere/cm^2	A/cm^2	0.1550
atmospheres	atm	kilopascals	kPa	101.325
British Thermal Unit	Btu	joules	J	1054.8
Btu	Btu	kilogram-metre	kg-m	107.56
Btu	Btu	kilowatt-hour	kWh	2.928×10^{-4}
Btu/hour	Btu/h	watt	W	0.2931
calorie, gram	cal or g-cal	joules	J	4.186
chain	chain	metre	m	20.11684
cubic foot	ft^3	cubic metre	m^3	0.02832
cubic foot	ft^3	litre	L	28.32
cubic foot/minute	cfm	litre/second	L/s	0.47195
cycle/second	c/s	Hertz	Hz	1.00
Fahrenheit	°F	Celsius	°C	(°F-32)/1.8
foot	ft	metre	m	0.3048
footcandle	fc	lux, lumen/ square metre	lx, lm/m^2	10.764
footlambert	fL	candela/square metre	cd/m^2	3.42626
foot-pounds	ft-lb	joule	J	1.356
foot-pounds	ft-lb	kilogram-metres	kg-m	0.1383
foot-pounds/second	ft-lb/s	kilowatt	kW	1.356×10^{-3}
gallons (Imp)	gal (Imp)	litres	L	4.546
gallons (US)	gal (US)	litres	L	3.785
grains/gallon (Imp)	gr/gal (Imp)	parts per million	ppm	14.286
grains/gallon (US)	gr/gal (US)	parts per million	ppm	17.118
horsepower	hp	watts	W	745.7
horsepower-hours	hp-h	joules	J	2.684×10^6
inches	in	centimetres	cm	2.540
inches of Mercury (@ 32°F)	in Hg	kilopascals	kPa	3.386
inches of water (@ 4°C)	in H_2O	kilopascals	kPa	0.2491

UNIT CONVERSION TABLES
IMPERIAL TO METRIC (cont'd)

FROM	SYMBOL	TO	SYMBOL	MULTIPLY BY
lamberts	* L	candela/square metre	cd/m^2	3.183
lumen/square foot	lm/ft^2	lumen/square metre	lm/m^2	10.76
lumen	lm	watt	W	0.001496
miles (statute)	mi	kilometres	km	1.6093
ounces	oz	grams	g	28.35
perm (at 0°C)	perm	kilogram per pascal-second-square metre	$kg/Pa\text{-}s\text{-}m^2$ (PERM)	5.721×10^{-11}
perm (at 23°C)	perm	kilogram per pascal-second-square metre	$kg/Pa\text{-}s\text{-}m^2$ (PERM)	5.745×10^{-11}
perm-inch (at 0°C)	perm. in.	kilogram per pascal-second-metre	kg/Pa-s-m	1.4532×10^{-12}
perm-inch (at 23°C)	perm. in.	kilogram per pascal-second-metre	kg/Pa-s-m	1.4593×10^{-12}
pint (Imp)	pt	litre	L	0.56826
pounds	lb	grams	g	453.5924
pounds	lb	joules/metre, (Newtons)	J/m, N	4.448
pounds	lb	kilograms	kg	0.4536
pounds	lb	tonne (metric)	t	4.536×10^{-4}
pounds/cubic foot	lb/ft^3	grams/litre	g/L	16.02
pounds/square inch	psi	kilopascals	kPa	6.89476
quarts	qt	litres	L	1.1365
slug	slug	kilograms	kg	14.5939
square foot	ft^2	square metre	m^2	0.09290
square inches	in^2	square centimetres	cm^2	6.452
square yards	yd^2	square metres	m^2	0.83613
tons (long)	ton	kilograms	kg	1016
tons (short)	tn	kilograms	kg	907.185
yards	yd	metres	m	0.9144

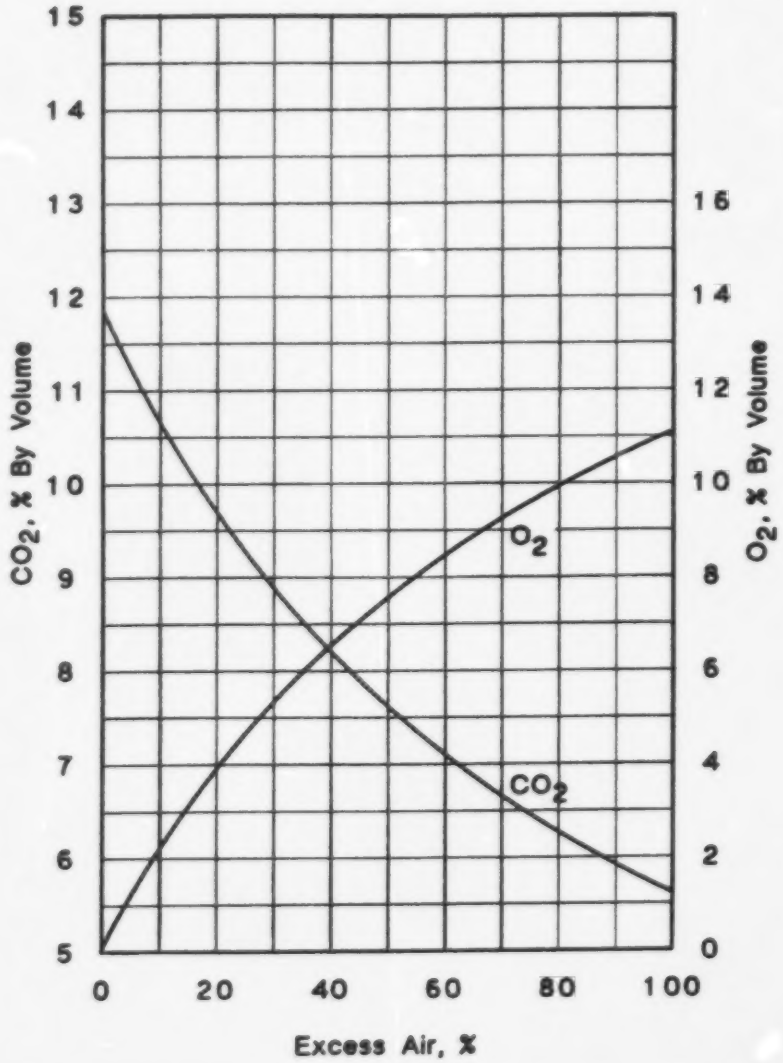
* "L" as used in Lighting

4138T/T33(-2)

The following typical values for conversion factors may be used when actual data are unavailable. The MJ and Btu equivalencies are heats of combustion. Hydrocarbons are shown at the higher heating value, wet basis. Some items listed are typically feedstocks, but are included for completeness and as a reference source. The conversion factors for coal are approximate since the heating value of a specific coal is dependent on the particular mine from which it is obtained.

Consistent factors must be used when calculating Base Year and Current Year energy usage.

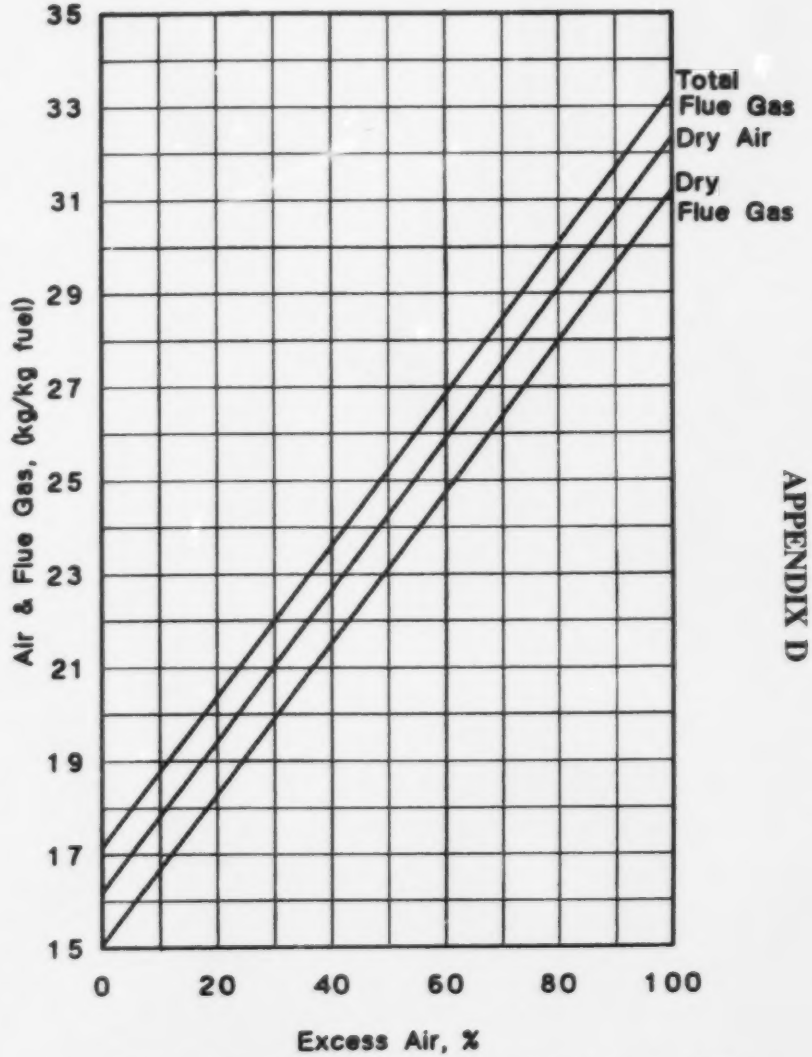
ENERGY TYPE	METRIC	IMPERIAL
COAL		
— metallurgical	29,000 megajoules/tonne	25.0×10^6 Btu/ton
— anthracite	30,000 megajoules/tonne	25.8×10^6 Btu/ton
— bituminous	32,100 megajoules/tonne	27.6×10^6 Btu/ton
— sub-bituminous	22,100 megajoules/tonne	19.0×10^6 Btu/ton
— lignite	16,700 megajoules/tonne	14.4×10^6 Btu/ton
COKE		
— metallurgical	30,200 megajoules/tonne	26.0×10^6 Btu/ton
— petroleum		
— raw	23,300 megajoules/tonne	20.0×10^6 Btu/ton
— calcined	32,600 megajoules/tonne	28.0×10^6 Btu/ton
PITCH	37,200 megajoules/tonne	32.0×10^6 Btu/ton
CRUDE OIL	38,5 megajoules/litre	5.8×10^6 Btu/bbl
No. 2 OIL	38.68 megajoules/litre	5.88×10^6 Btu/bbl $.168 \times 10^6$ Btu/IG
No. 4 OIL	40.1 megajoules/litre	6.04×10^6 Btu/bbl $.173 \times 10^6$ Btu/IG
No. 6 OIL (RESID. BUNKER C)		
@ 2.5% sulphur	42.3 megajoules/litre	6.38×10^6 Btu/bbl $.182 \times 10^6$ Btu/IG
@ 1.0% sulphur	40.5 megajoules/litre	6.11×10^6 Btu/bbl $.174 \times 10^6$ Btu/IG
@ .5% sulphur	40.2 megajoules/litre	6.05×10^6 Btu/bbl $.173 \times 10^6$ Btu/IG
KEROSENE	37.68 megajoules/litre	$.167 \times 10^6$ Btu/IG
DIESEL FUEL	38.68 megajoules/litre	$.172 \times 10^6$ Btu/IG
GASOLINE	36.2 megajoules/litre	$.156 \times 10^6$ Btu/IG
NATURAL GAS	37.2 megajoules/m^3	1.00×10^6 Btu/MCF
PROPANE	50.3 megajoules/kg 26.6 megajoules/litre	$.02165 \times 10^6$ Btu/lb $.1145 \times 10^6$ Btu/IG
ELECTRICITY	3.6 megajoules/kWh	$.003413 \times 10^6$ Btu/kWh



RELATIONSHIP OF EXCESS AIR TO CO_2 AND O_2 LEVELS

Fuel: Natural Gas (1007 Btu/ft^3)

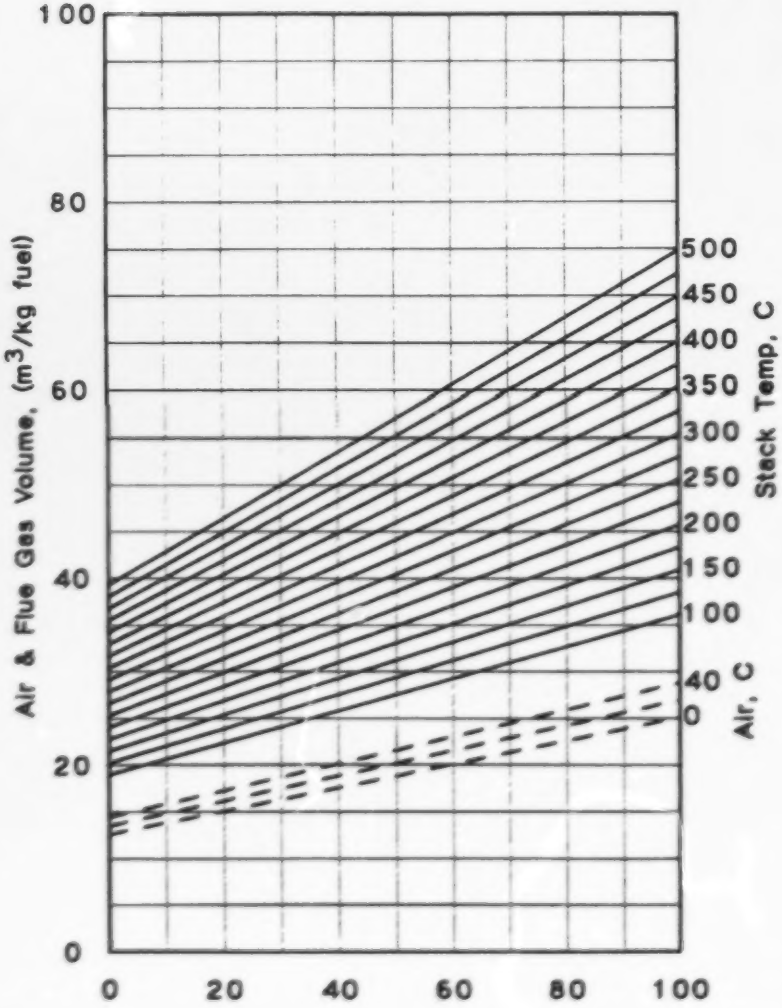
FIGURE 1



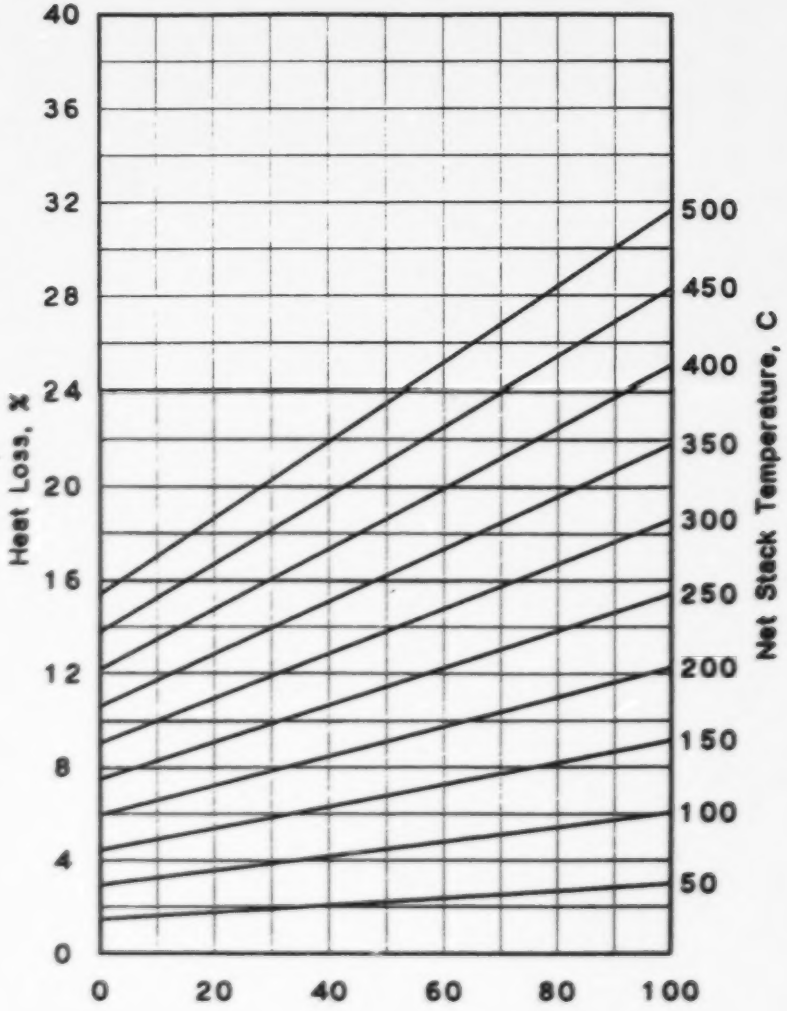
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (WEIGHT BASIS)

Fuel: Natural Gas (1007 Btu/ft^3)

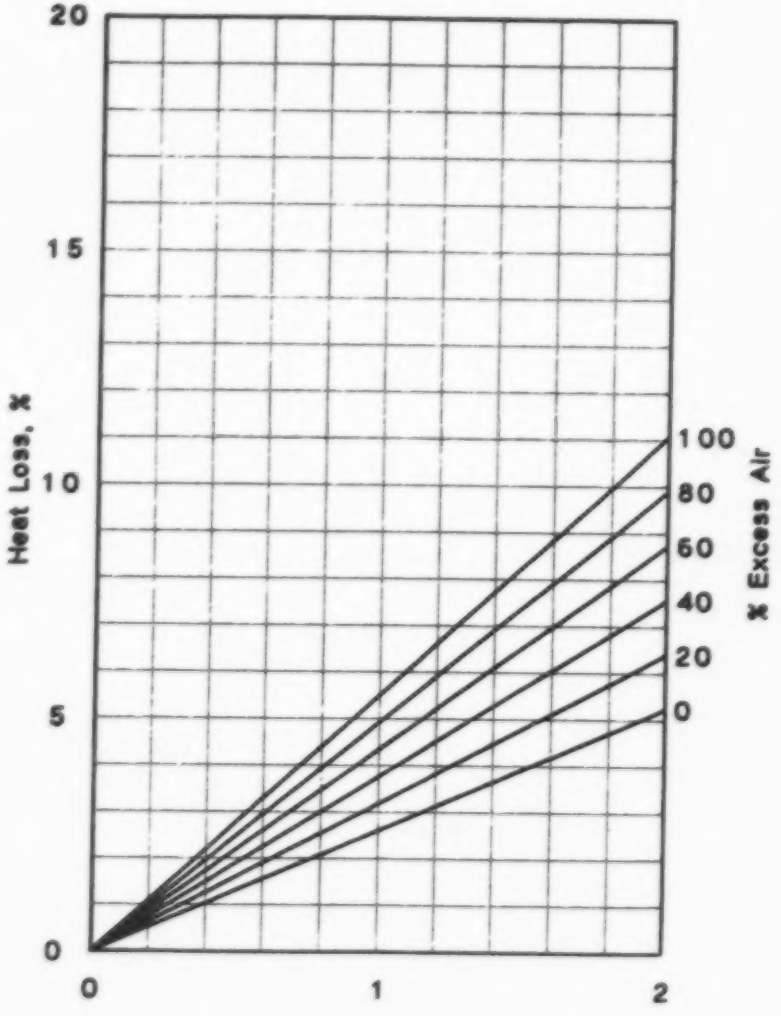
FIGURE 2



RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (VOLUME BASIS)
Fuel: Natural Gas (1007 Btu/ft^3)
FIGURE 3



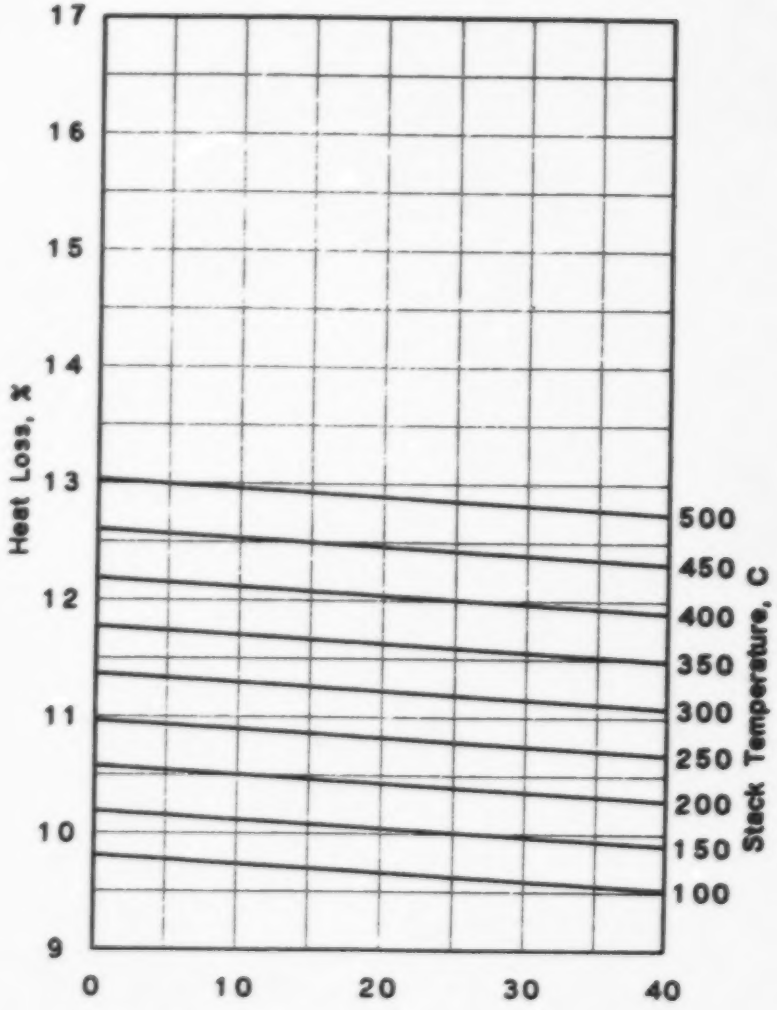
RELATIONSHIP OF EXCESS AIR TO DRY FLUE GAS HEAT LOSS AT VARYING NET STACK TEMPERATURES
Fuel: Natural Gas (1007 Btu/ft^3)
FIGURE 4



RELATIONSHIP OF CO IN FLUE GAS TO HEAT LOSS AT VARYING LEVELS OF EXCESS AIR

Fuel: Natural Gas (1007 Btu/ft^3)

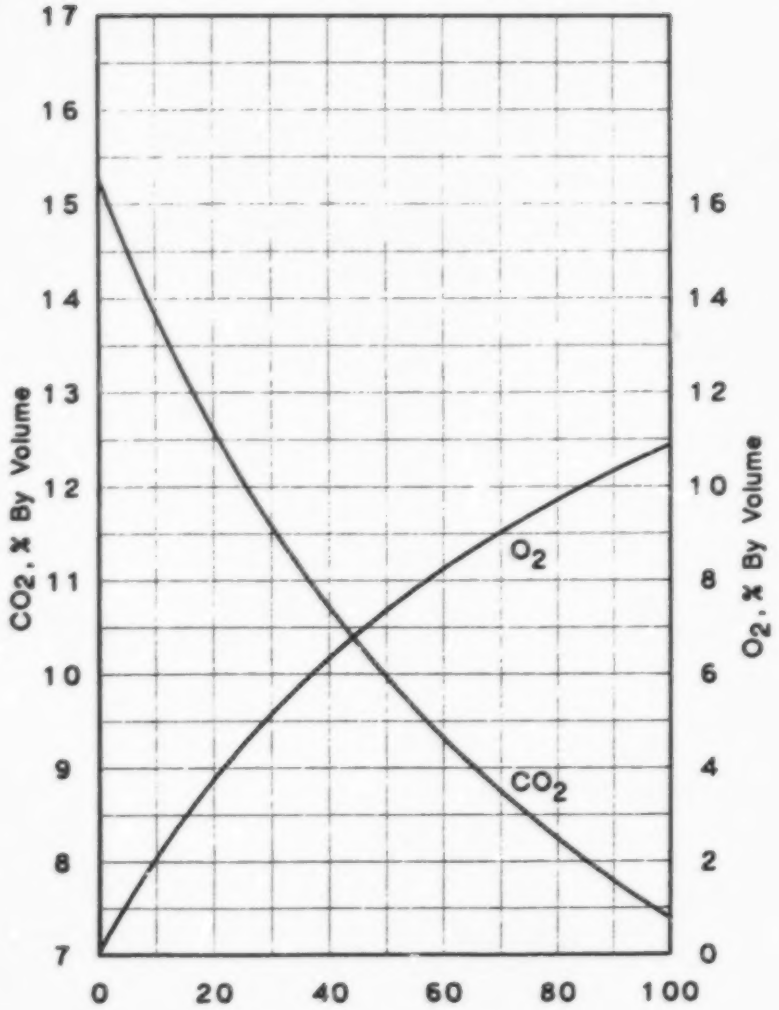
FIGURE 5



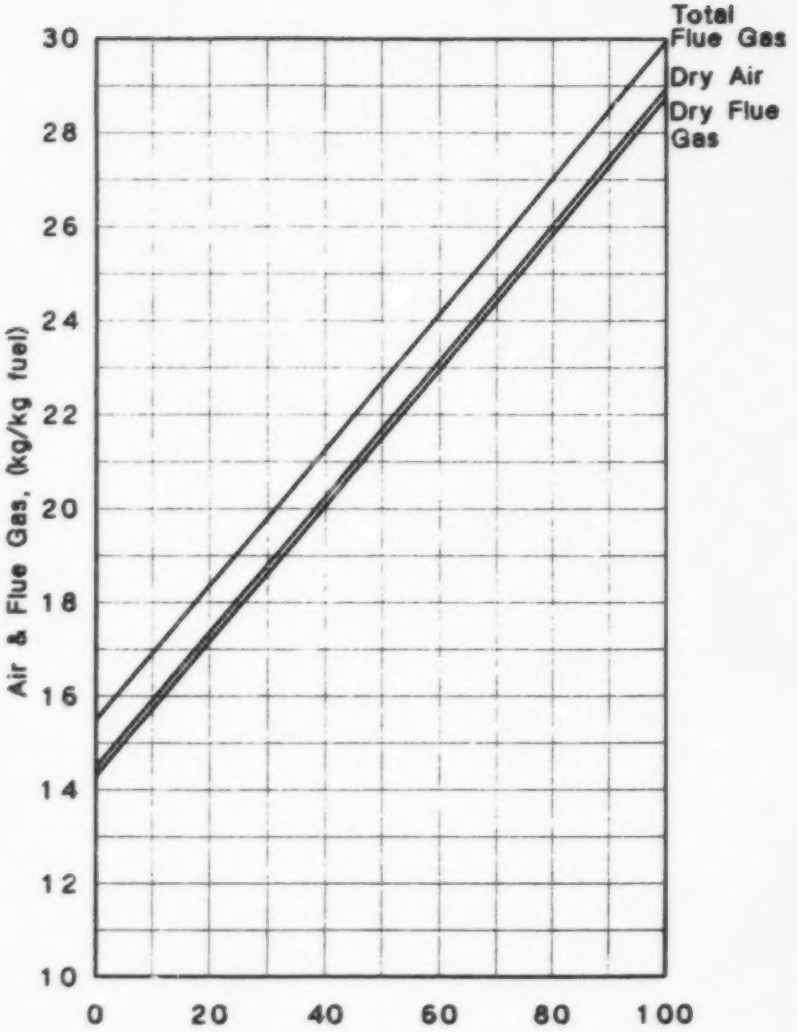
RELATIONSHIP OF COMBUSTION AIR TEMPERATURE TO HEAT LOSS DUE TO FORMATION OF WATER IN FLUE GAS (HYDROGEN LOSS)

Fuel: Natural Gas (1007 Btu/ft^3)

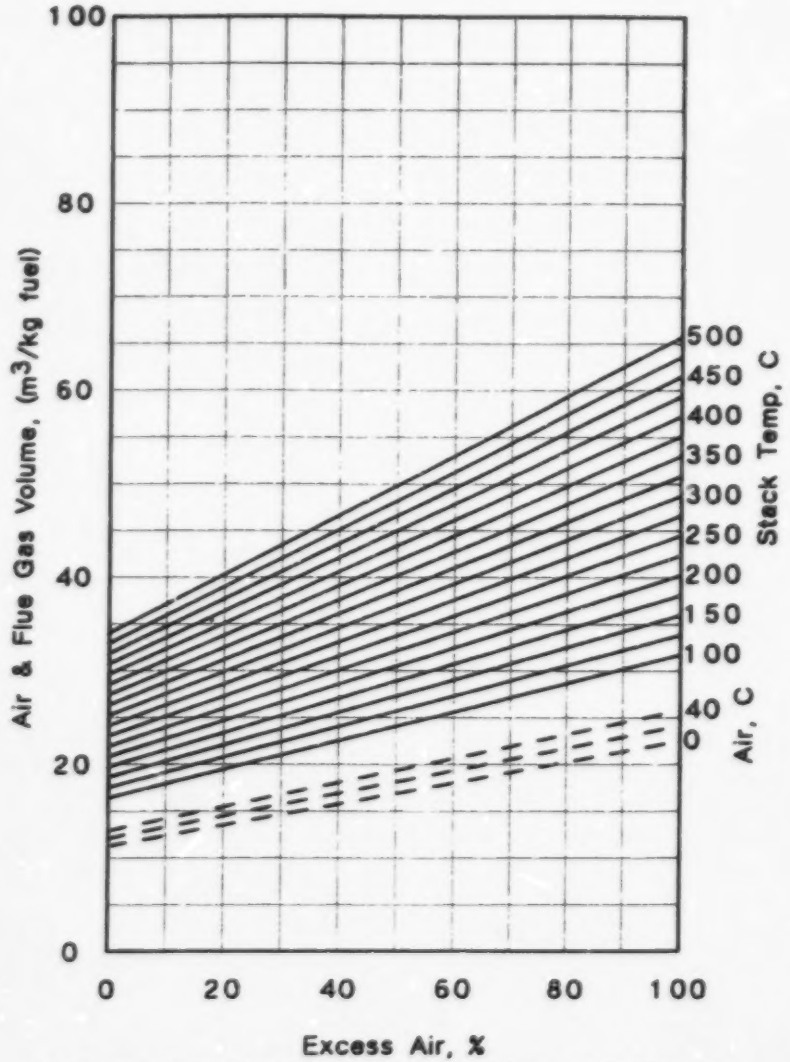
FIGURE 6



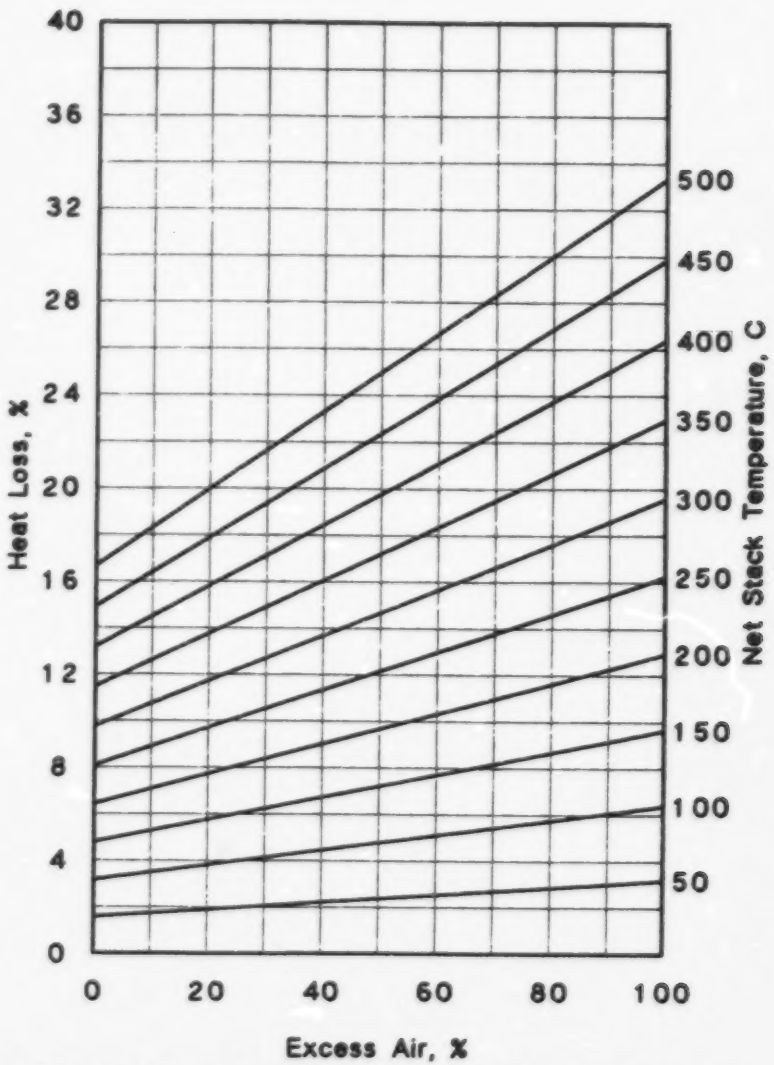
RELATIONSHIP OF EXCESS AIR TO CO_2 AND O_2 LEVELS
Fuel: No. 2 Fuel Oil
FIGURE 7



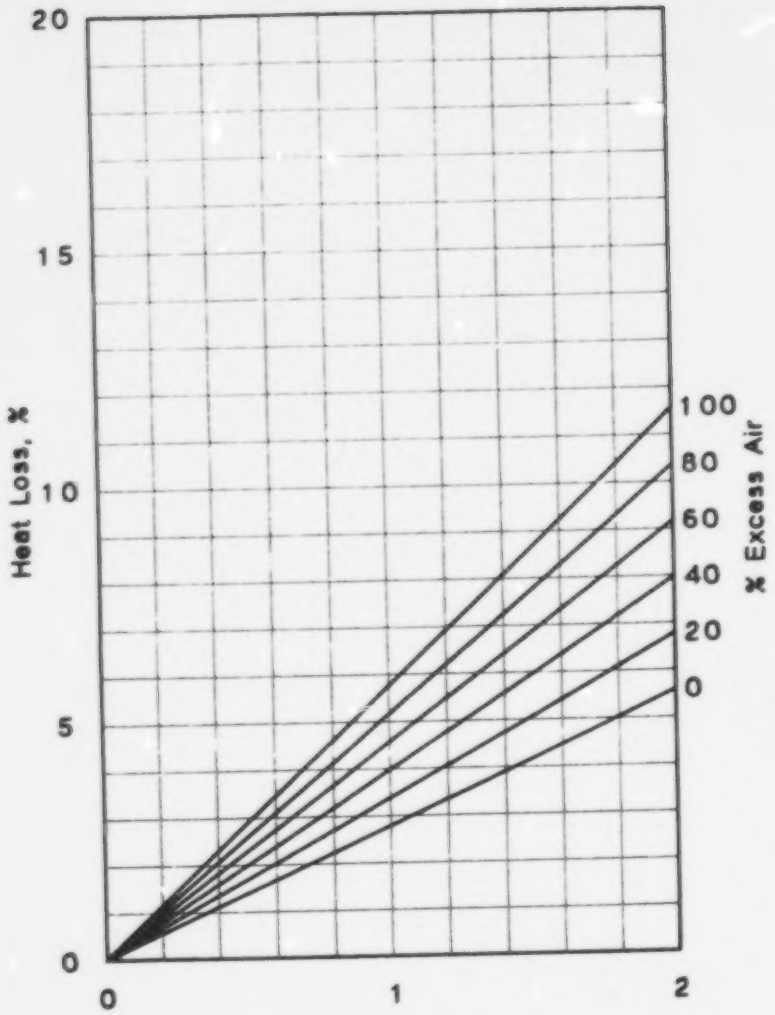
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (WEIGHT BASIS)
Fuel: No. 2 Fuel Oil
FIGURE 8



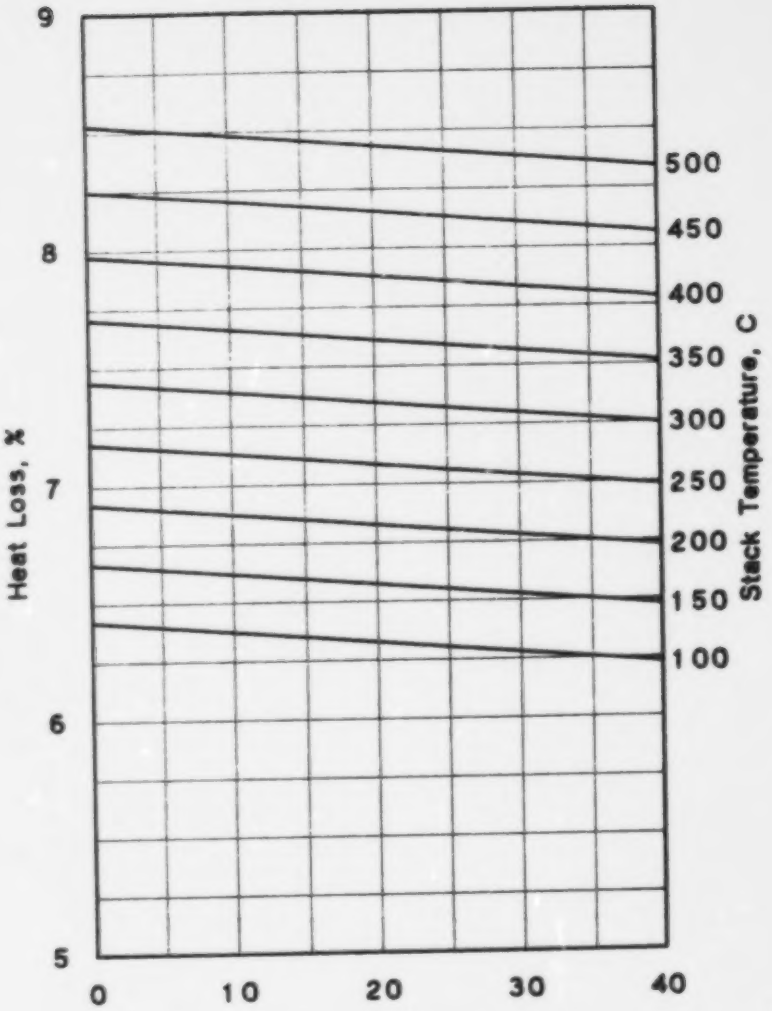
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (VOLUME BASIS)
Fuel. No. 2 Fuel Oil
FIGURE 9



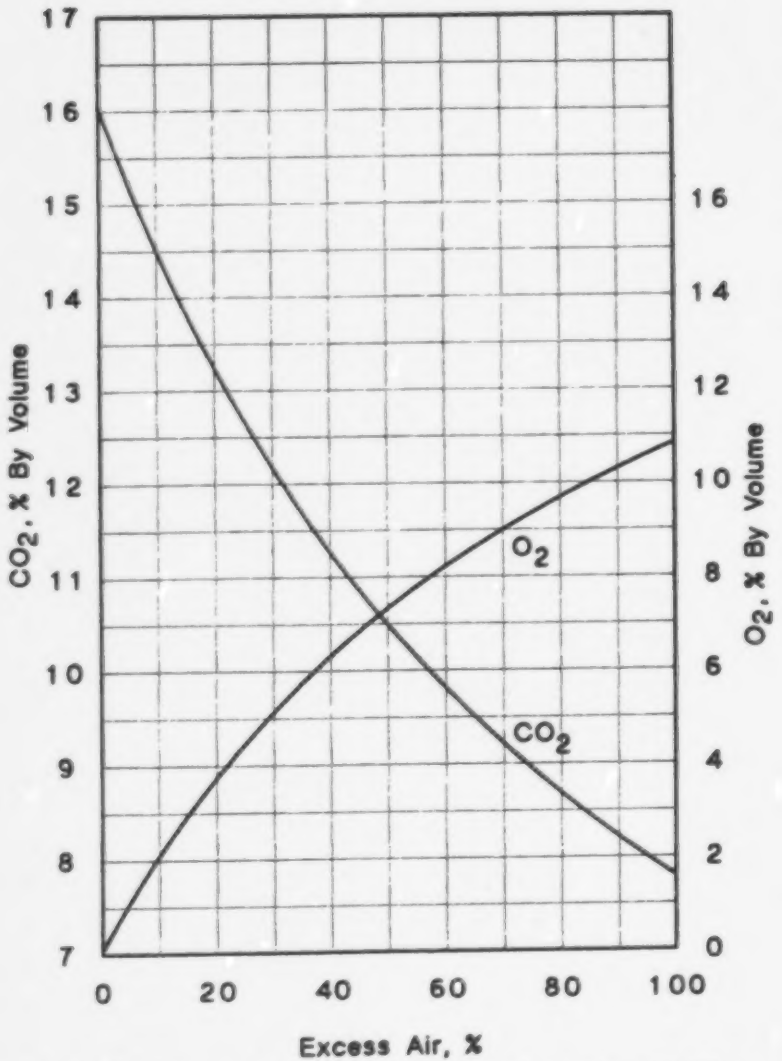
RELATIONSHIP OF EXCESS AIR TO DRY FLUE GAS HEAT LOSS AT VARYING NET STACK TEMPERATURES
Fuel: No. 2 Fuel Oil
FIGURE 10



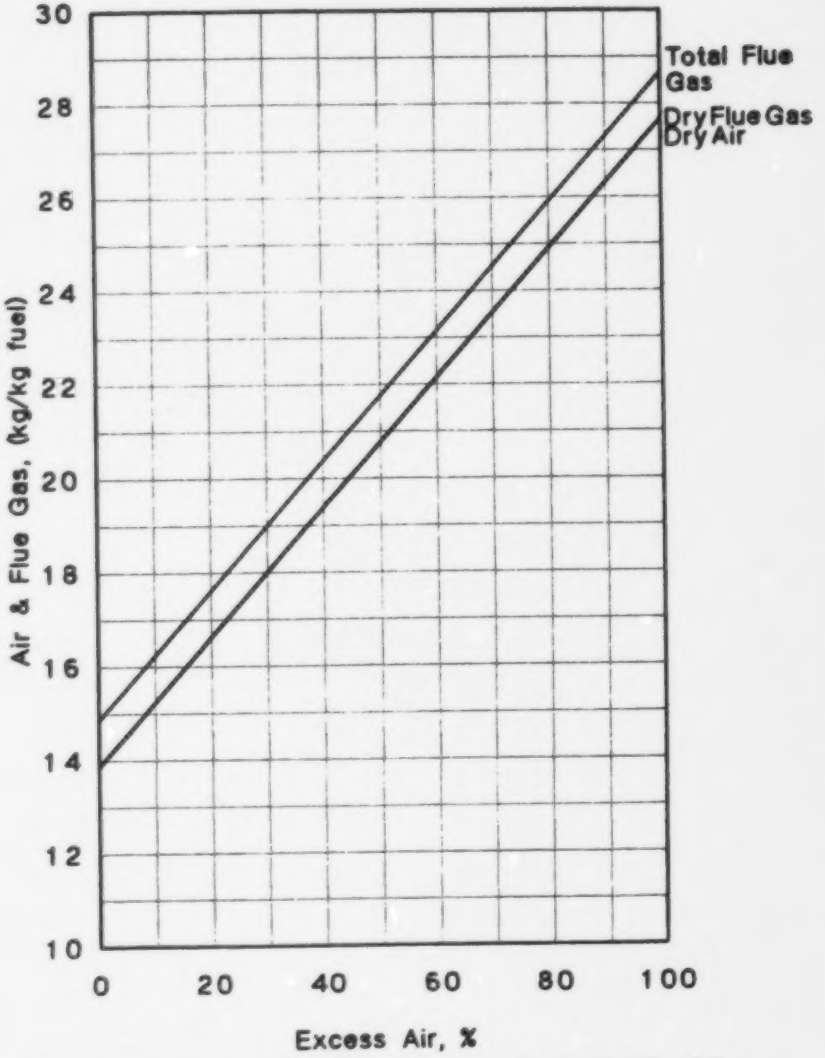
RELATIONSHIP OF CO IN FLUE GAS TO HEAT LOSS
AT VARYING LEVELS OF EXCESS AIR
Fuel: No. 2 Fuel Oil
FIGURE 11



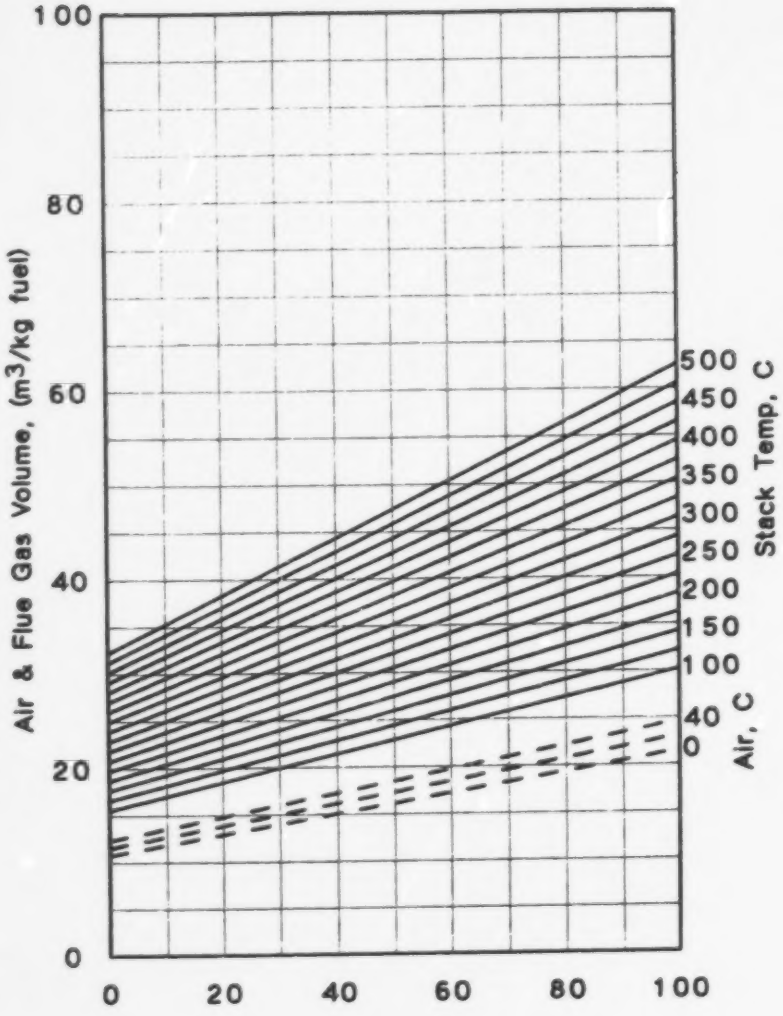
RELATIONSHIP OF COMBUSTION AIR TEMPERATURE TO
HEAT LOSS DUE TO FORMATION OF WATER IN FLUE GAS
(HYDROGEN LOSS)
Fuel: No. 2 Fuel Oil
FIGURE 12



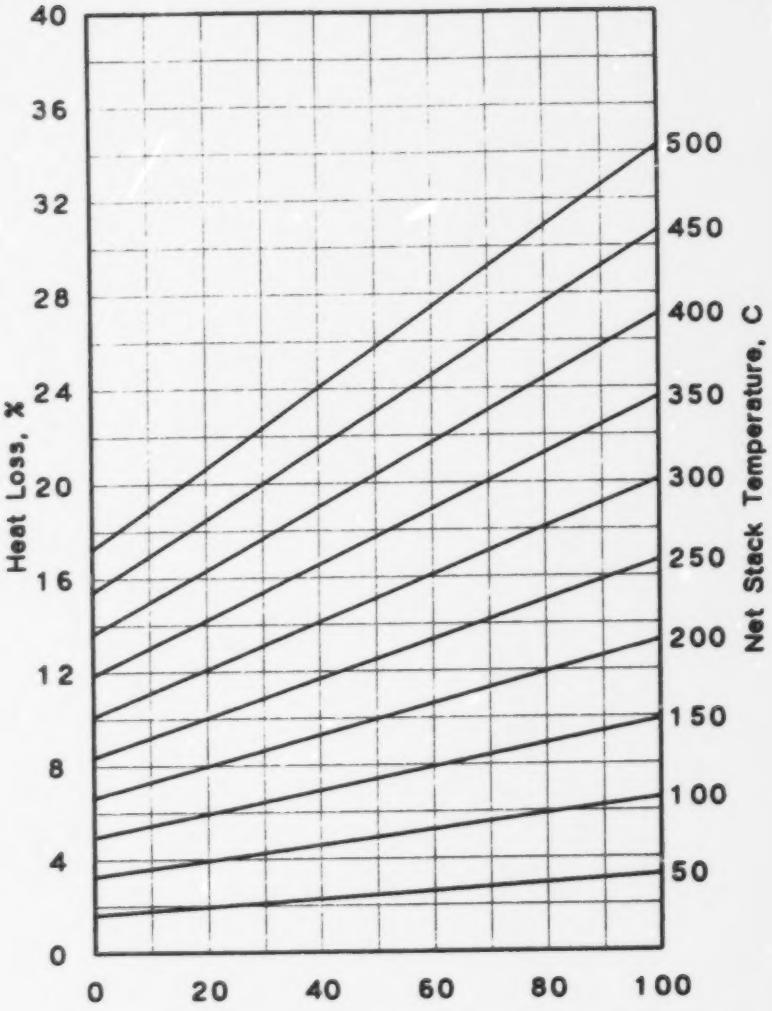
RELATIONSHIP OF EXCESS AIR TO CO_2 AND O_2 LEVELS
Fuel: No. 6 Fuel Oil
FIGURE 13



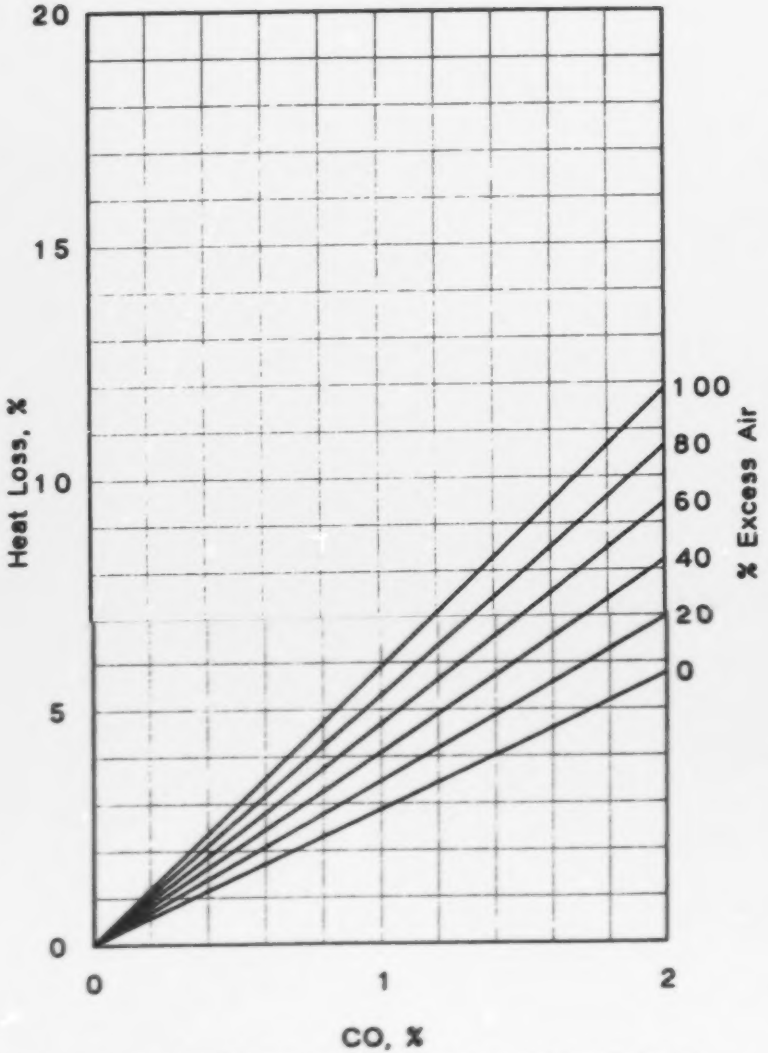
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (WEIGHT BASIS)
Fuel: No. 6 Fuel Oil
FIGURE 14



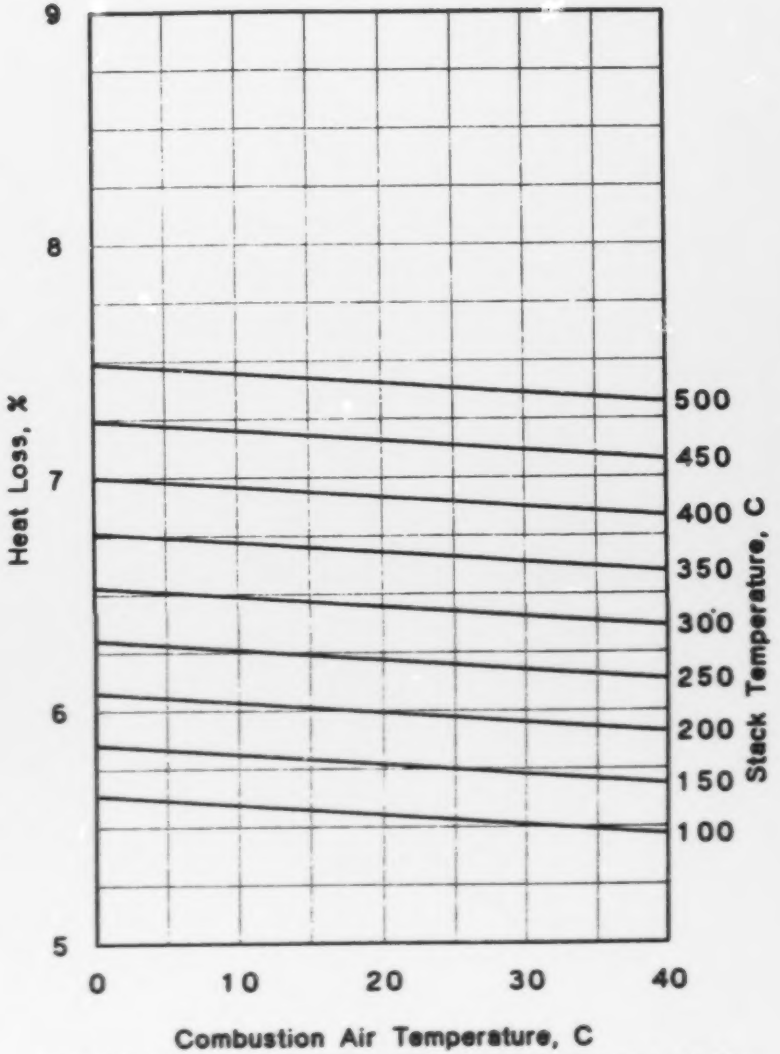
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (VOLUME BASIS)
Fuel: No. 6 Fuel Oil
FIGURE 15



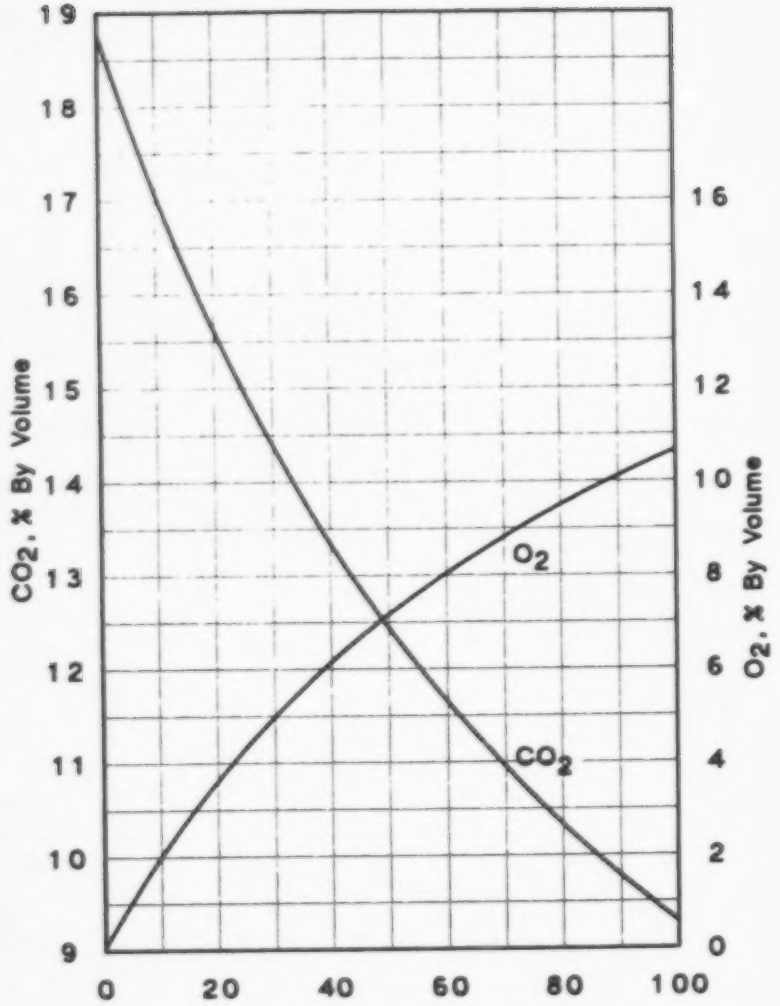
RELATIONSHIP OF EXCESS AIR TO DRY FLUE GAS HEAT LOSS AT VARYING NET STACK TEMPERATURES
Fuel: No. 6 Fuel Oil
FIGURE 16



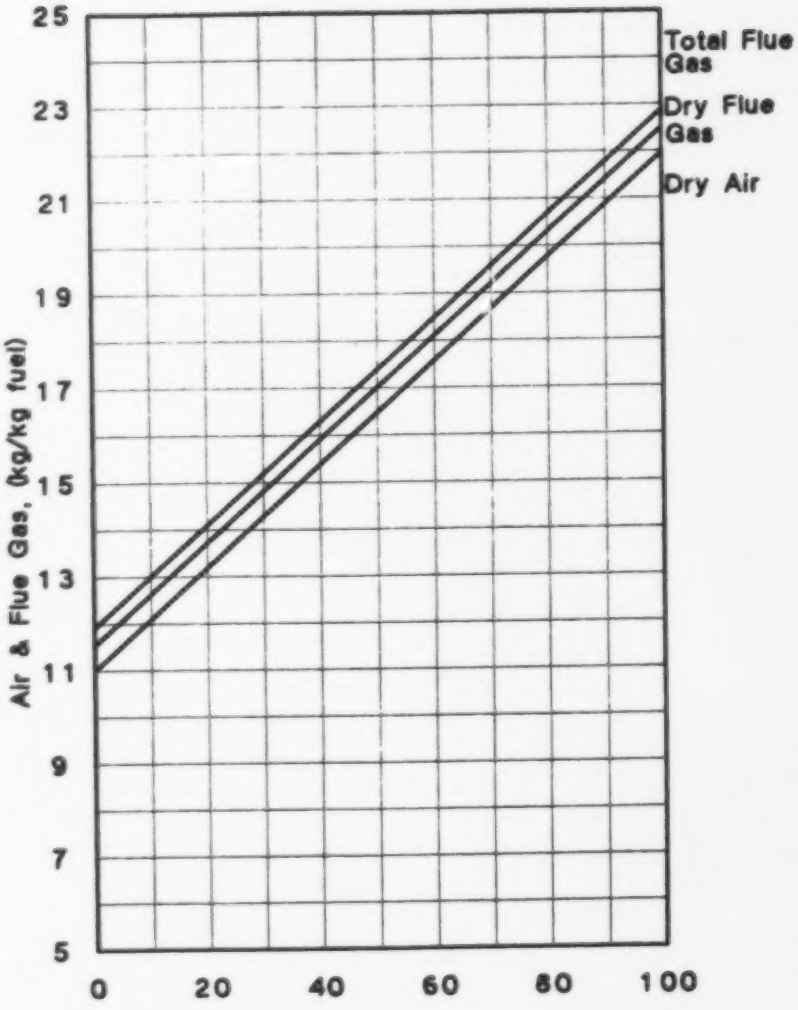
RELATIONSHIP OF CO IN FLUE GAS TO HEAT LOSS
AT VARYING LEVELS OF EXCESS AIR
Fuel: No. 6 Fuel Oil
FIGURE 17



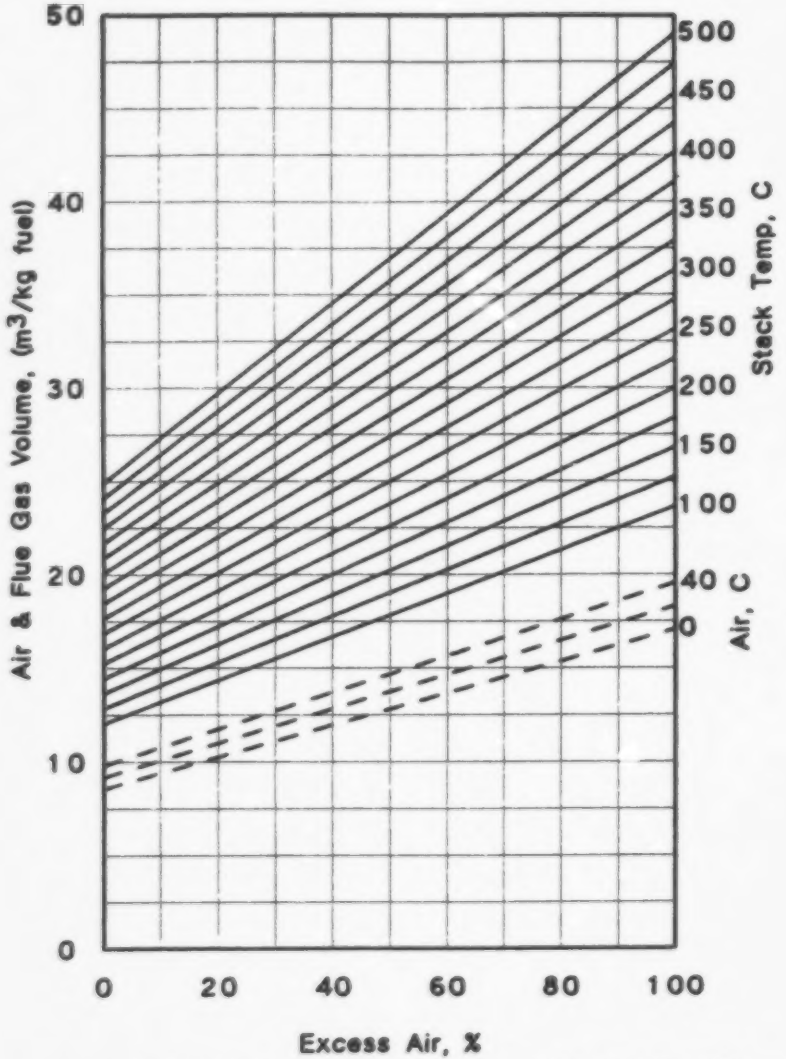
RELATIONSHIP OF COMBUSTION AIR TEMPERATURE TO
HEAT LOSS DUE TO FORMATION OF WATER IN FLUE GAS
(HYDROGEN LOSS)
Fuel: No. 6 Fuel Oil
FIGURE 18



RELATIONSHIP OF EXCESS AIR TO CO_2 AND O_2 LEVELS
Fuel: Alberta/BC Bituminous Coal
FIGURE 19



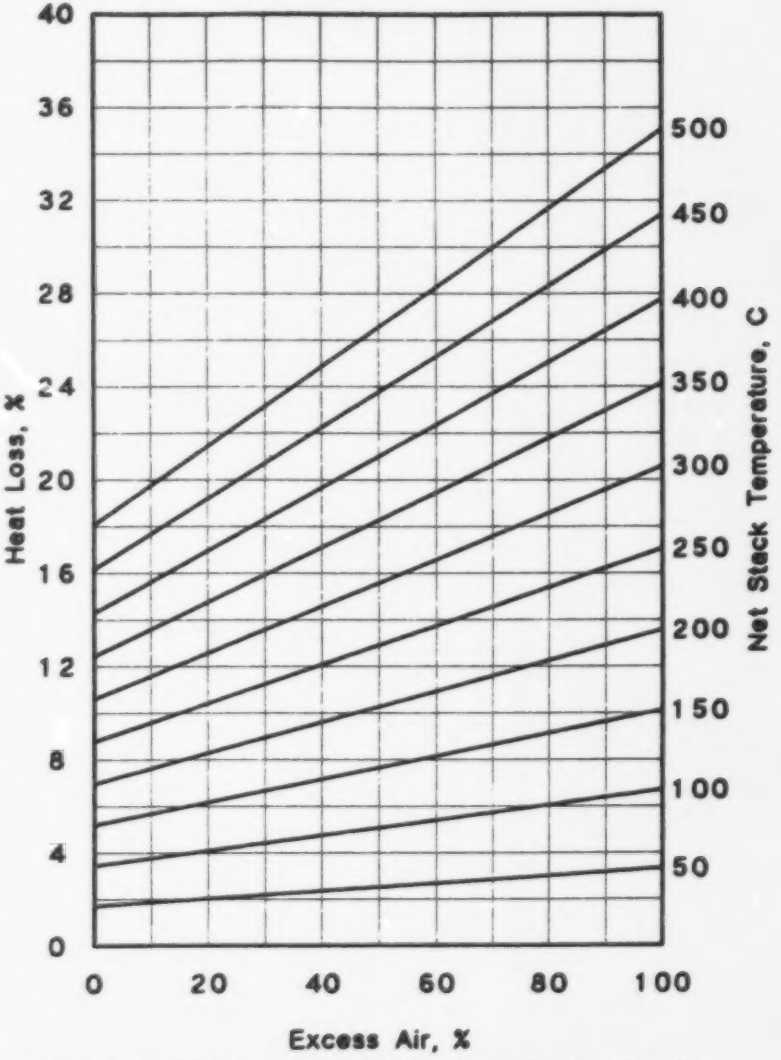
RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (WEIGHT BASIS)
Fuel: Alberta/BC Bituminous Coal
FIGURE 20



RELATIONSHIP OF EXCESS AIR TO RATIOS OF AIR AND FLUE GAS TO FUEL BURNED (VOLUME BASIS)

Fuel: Alberta/BC Bituminous Coal

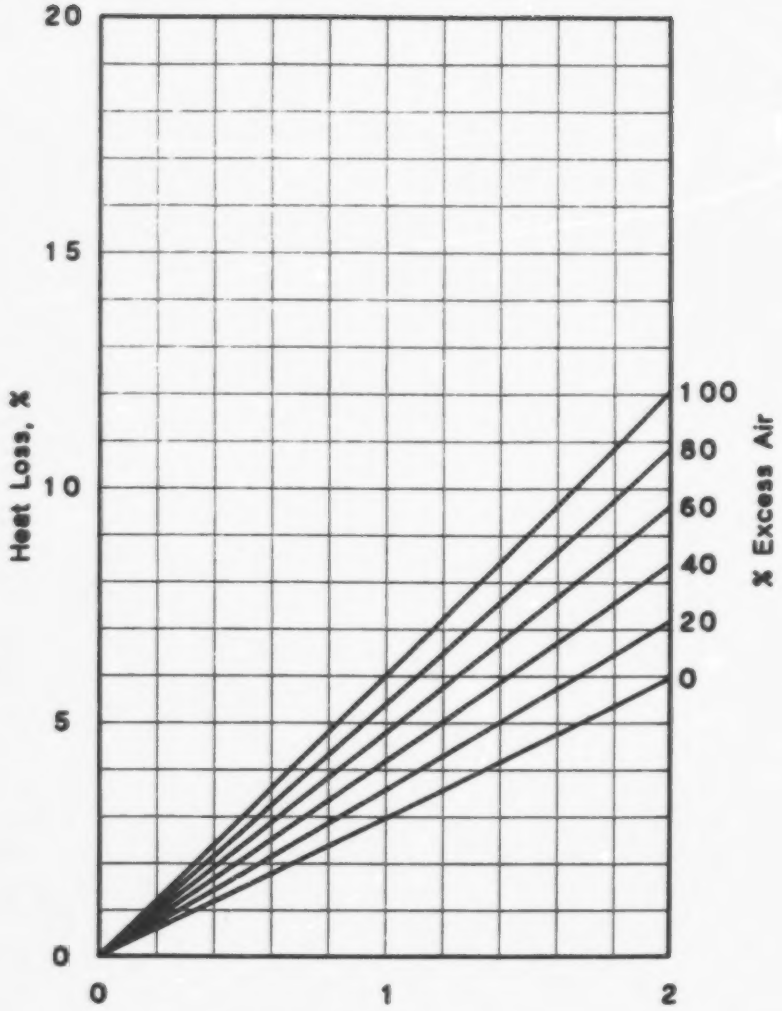
FIGURE 21



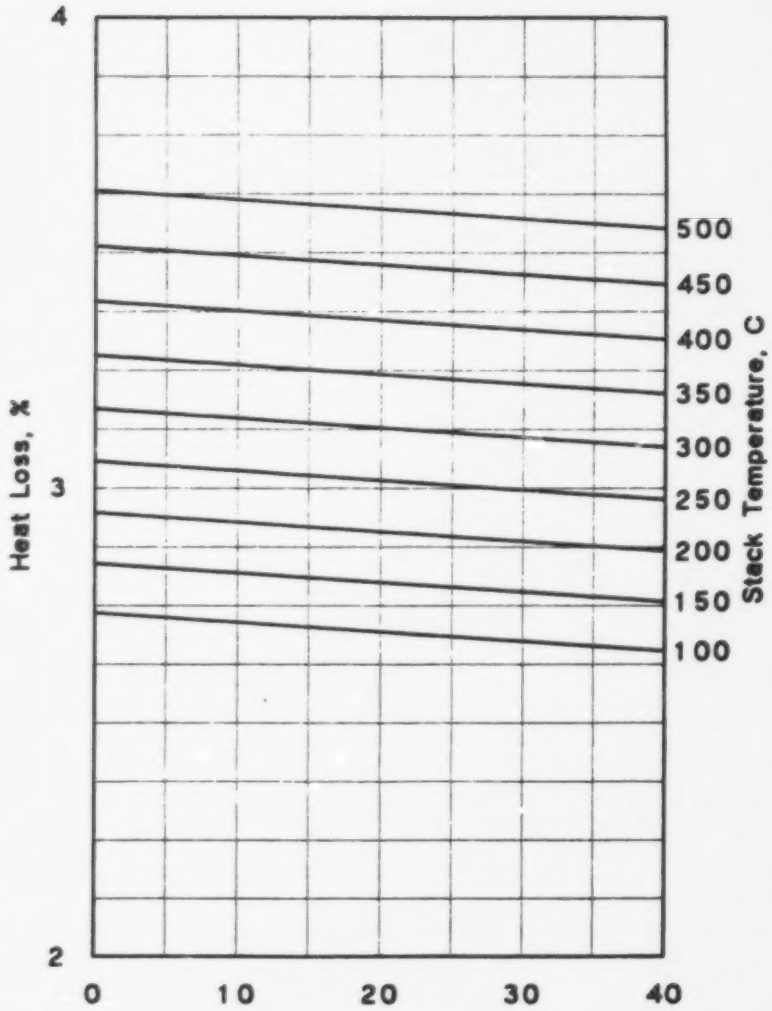
RELATIONSHIP OF EXCESS AIR TO DRY FLUE GAS HEAT LOSS AT VARYING NET STACK TEMPERATURES

Fuel: Alberta/BC Bituminous Coal

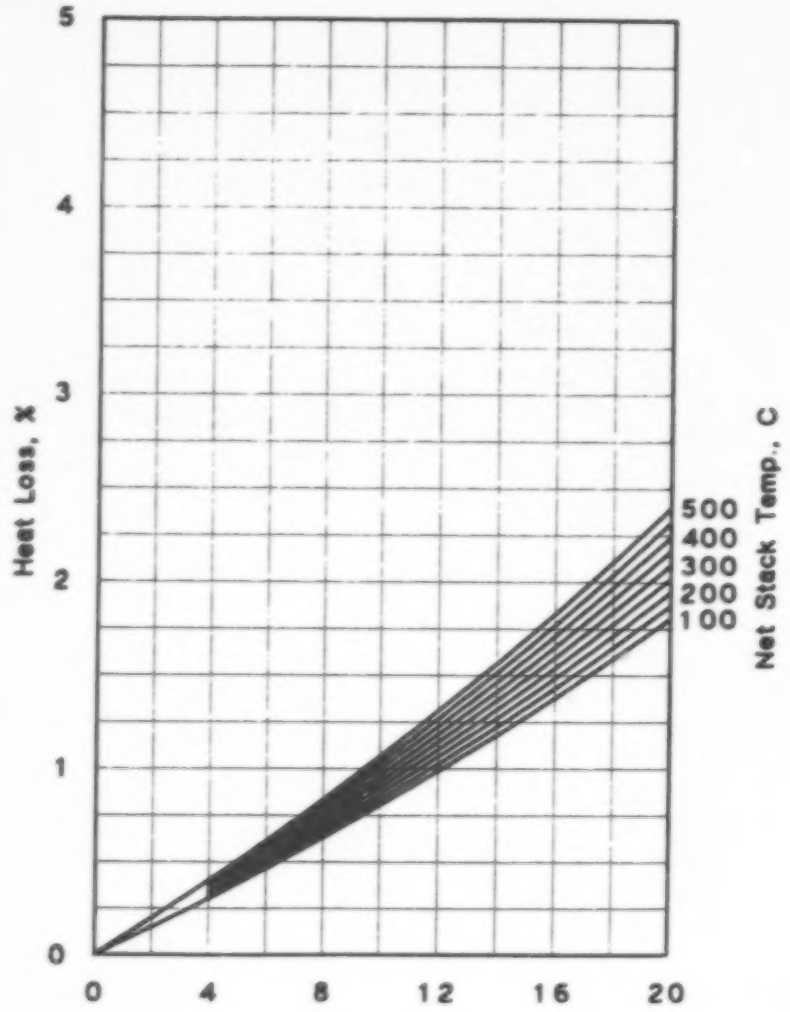
FIGURE 22



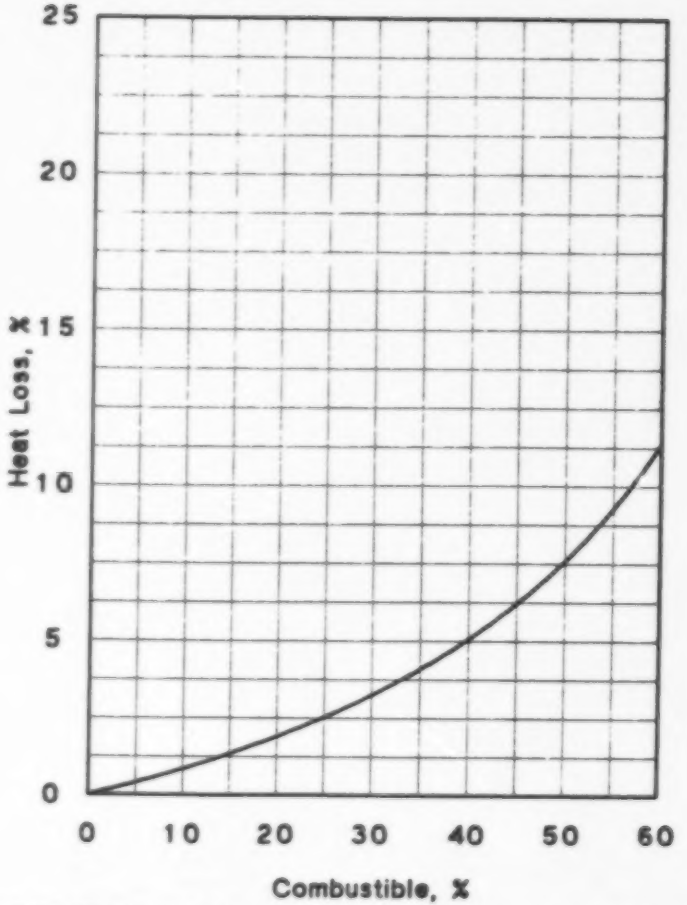
RELATIONSHIP OF CO IN FLUE GAS TO HEAT LOSS
AT VARYING LEVELS OF EXCESS AIR
Fuel: Alberta/BC Bituminous Coal
FIGURE 23



RELATIONSHIP OF COMBUSTION AIR TEMPERATURE TO
HEAT LOSS DUE TO FORMATION OF WATER IN FLUE GAS
(HYDROGEN LOSS)
Fuel: Alberta/BC Bituminous Coal
FIGURE 24



RELATIONSHIP OF MOISTURE CONTENT IN FUEL TO HEAT LOSS AT VARYING NET STACK TEMPERATURES
Fuel: Alberta/BC Bituminous Coal
FIGURE 25



RELATIONSHIP OF LEVEL OF COMBUSTIBLE REFUSE TO HEAT LOSS
Fuel: Alberta/BC Bituminous Coal
FIGURE 26

Combustion System Efficiency Test
(Direct Method)
Worksheet 5-1

Company: _____ Date: _____

Location: _____ By: _____

Equipment _____ Fuel Fired: _____

Rated Capacity: _____ Test No.: _____

Steam pressure	_____	kPa(abs)	
Feedwater temperature	_____	°C	
Enthalpy of saturated/superheated steam	_____	kJ/kg	(1)
Enthalpy of saturated feedwater to boiler economizer	_____	kJ/kg	(2)
Enthalpy of saturated liquid (boiler water)	_____	kJ/kg	(3)
Heat absorbed/kg of steam (1) — (2)	_____	kJ/kg	(4)
Actual water evaporated	_____	kg/h	(5)
Rate of fuel firing (as-fired weight)$_a$	_____	kg/h	(6)
Fuel heating value (kJ/kg as-fired)$_b$	_____	kJ/kg	(7)
Total heat input (6) x (7)	_____	kJ/h	(8)
Rate of boiler blowdown	_____	kg/h	(9)
Heat output in blowdown water (9) x [(3) − (2)]	_____	kJ/h	(10)
Total heat output [(5) x (4)] + (10)	_____	kJ/h	(11)
Direct efficiency $\frac{(11)}{(8)}$ x 100	_____	%	

$_a$ use m^3/h for natural gas

$_b$ use kJ/m^3 for natural gas

Combustion System Efficiency Test
(Direct Method)
Worksheet 5-2

Company: _____ Date: _____

Location: _____ By: _____

Equipment _____ Fuel Fired: _____

Rated Capacity: _____ Test No.: _____

TEST DATA

Stack Temp.: _____ °C (1) Combustion Air Temp.: _____ °C (2)

% O_2 in Flue Gas: _____ % (3) % CO in Flue Gas: _____ % (4)

Excess Air[a]: _____ % (5) Dry Flue Gas Loss[b]: _____ % (6)

Hydrogen Loss[c]: _____ % (7) Radiation Loss[d]: _____ % (8)

Carbon Monoxide Loss[e]: _____ % (9) Unaccounted for Loss[f]: _____ % (10)

COAL ONLY

Combustible Refuse Loss: _____ % (11)
(Appendix D, Figure 26)

Moisture Loss (Appendix D, Figure 25):
_____ % (12)

TOTAL LOSSES

(Sum of (6) to (12)): _____ % (13)

INDIRECT EFFICIENCY = 100 — (13)

= _____ %

NOTES:
[a] Use the measured 0_2 % with Appendix D, Figure 1, 7, 13, or 19 (depending on fuel used) to determine excess air per cent.
[b] Use Appendix D, Figure 4, 10, 16, or 22 (depending on fuel used) to determine dry flue gas loss.
[c] Use Appendix D, Figure 6, 12, 18, or 24 (depending on fuel used) to determine hydrogen loss.
[d] Use Table 3 for furnaces, ovens and kilns and Table 4 for boilers.
[e] Use Appendix D, Figure 5, 11, 17 or 23 (depending on fuel used) to determine carbon monoxide loss.
[f] Usually 1%.